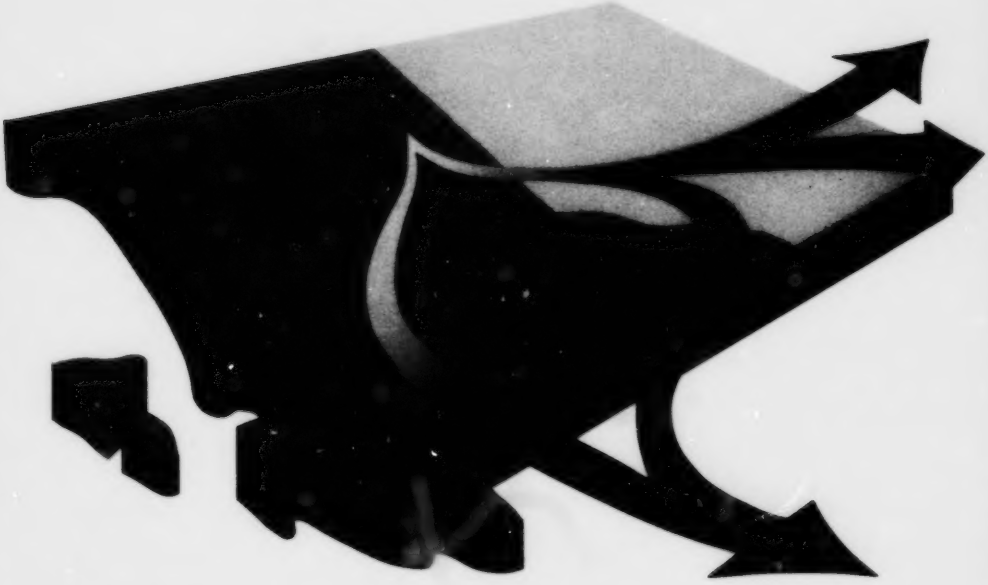
Markets for British Columbia Natural Gas



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MARKETS FOR BRITISH COLUMBIA NATURAL GAS

DAVID H. MAERZ AND
LEONARD A. COAD

Markets for British Columbia Natural Gas

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PREFACE

The authors wish to express their appreciation to the study's advisory committee for their contribution to the research process in terms of the provision of information and insightful comments. Thanks are due to the staff of Decision Focus Inc. who have continued to provide excellent support and guidance in the use of the NARG model. The special contribution of Dr. A. J. MacFadyen of the University of Calgary is recognized and greatly appreciated. The comments provided by Dr. J. G. Rowse of the University of Calgary are also appreciated.

Thanks are also due to a number of Institute staff involved in the production of this document: Beverly Kovacs, who prepared and coordinated the publishing of the final document; Megan Murphy, who created the graphics; and Nancy Sanford, who provided editorial assistance. Special thanks are given to Gerry Angevine for his helpful comments on the final draft, and to Tony Reinsch for his insight, guidance and support throughout the course of the study.

EXECUTIVE SUMMARY

Interest in the search for natural gas in British Columbia has increased dramatically over the last three years. Exploration and development activity have soared at a time when upstream activity in many other areas has been modest.

In CERI Study 32, *Continental Natural Gas Market, Canadian Export Capacity in the 90s*, significant promise was suggested for development of British Columbia natural gas reserves. This study provides a more detailed evaluation of the outlook for the British Columbia natural gas industry and examines the fundamentals underlying both the increase in recent activity and the longer-term outlook for the natural gas sector in that province's economy.

Framework for Analysis and Input Assumptions

The analysis of future developments in the production and marketing of natural gas in British Columbia is based on applications of the North American Regional Gas (NARG) model, developed by Decision Focus Inc. For the current study, a number of modifications were made to the NARG model to allow for detailed analysis of the British Columbia gas system.

Demand data for domestic gas consumption was obtained from the British Columbia Ministry of Energy, Mines and Petroleum Resources (MEMPR). The outlook for domestic markets includes the Pacific Coast Energy Corporation project to provide natural gas service to Vancouver Island.

The level of natural gas resource assumed in this study for northeastern British Columbia corresponds to an ultimate potential of 50 Tcf. This is comprised of 6.8 Tcf of cumulative production to December 31, 1987 and 43 Tcf of existing reserves and undiscovered potential. Consultation with officials from the British Columbia MEMPR, the Geological Survey of Canada and several major northeastern British Columbia producers suggests that a level of 50 Tcf for ultimate potential is reasonable, based on current information.

The natural gas cost curve input into the model for British Columbia was derived by the British Columbia MEMPR. The marginal cost curves for British Columbia and Alberta are provided in

Appendix B to this study. For connected reserves, the assumption made throughout the NARG framework is that reserves are represented to be available at operating cost alone. The operating cost employed in this study for connected reserves is based upon the British Columbia MEMPR's Producer Cost Allowance Survey, which represents costs associated with dehydration and compression of gas. To this is added the gathering cost to transport the gas to a processing facility, based upon the Westcoast Pipeline toll. The operating cost associated with remaining established connected reserves is $US 0.32/Mcf for the 4.8 Tcf of remaining connected reserves. Unconnected reserves, estimated at 2.8 Tcf at December 31, 1987, are made available at an average supply cost of $US 0.49/Mcf.

A number of capacity links were added to the NARG model to represent potential access of British Columbia gas resources to expanded export markets. Links were added to the model to reflect movement of British Columbia supply directly into the northern California and Rocky Mountain regions, and movement of Rocky Mountain region supply directly into the southern California utility market.

The British Columbia to Rocky Mountain transportation link can be thought of as representing movement on Northwest Pipeline's system, and movement on the Pacific Gas Transmission Company (PGT) system in the case of the California link. Currently, capacity does not exist to physically place gas onto the PGT system from Northwest Pipeline, but could easily be made available through the addition of compression to bring supply on Northwest Pipeline to a pressure sufficient to move it onto the PGT system.

Movement of British Columbia gas supplies into Alberta and on to other markets is represented by the addition of a market allocation process at the British Columbia/Alberta border. The capacity of this link--265 MMcf/d--reflects the maximum expandable capacity of the Gordondale lateral, linking the Westcoast and NOVA systems. Links were then added from the allocation process at the British Columbia/Alberta border to points of export from Alberta.

Results and Conclusions

In reviewing the results presented in this study, the reader is reminded that the intention of this work is to take a long-term view of likely market developments, based upon the general assumptions underlying the analysis.

The reference case outlook for British Columbia production and average wellhead prices is provided in Figure 1. Most striking is the significant growth in British Columbia production over the outlook period. This result suggests that within the next few years, the Westcoast Pipeline system will approach full capacity utilization for the first time since the early 1970s.

High rates of utilization on the Westcoast system underscore the need for significant capacity expansion if the production levels projected for the mid-1990s are to be achieved. It is currently understood that expansion on Westcoast to increase export capacity by about 200 MMcf/d could be accomplished without an increase in tolls, and that processing capacity will likely be expanded at the McMahon and Pine Lake processing facilities in the near future. It is also important to note that expansion of the Gordondale lateral made available to the model was fully utilized. Therefore, not all of the British Columbia gas production brought onstream is transported via the Westcoast mainline.

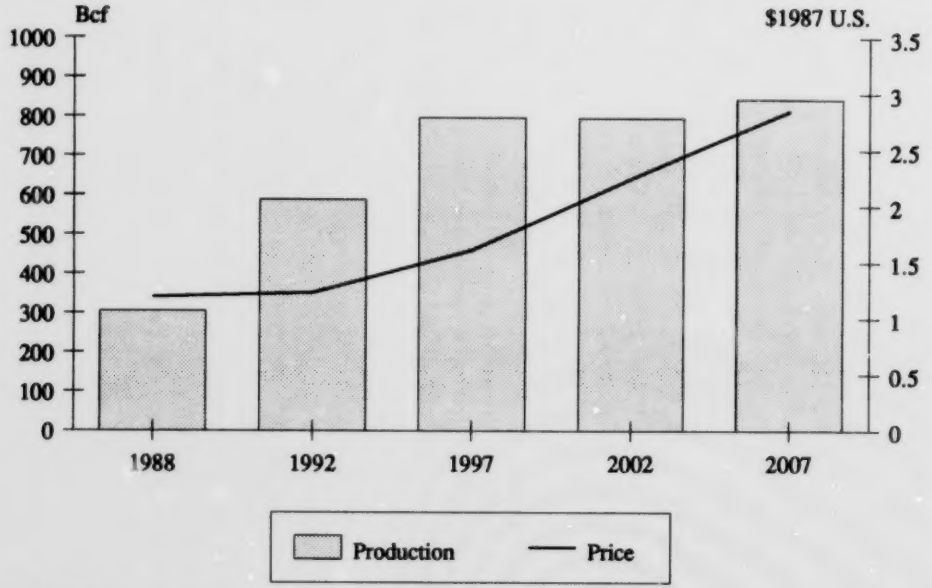
The significant gains projected for British Columbia gas production suggest the need for large increases in productive capacity by the mid-1990s. Natural gas production in the province is sustained at the 800 Bcf level from the mid-1990s through the end of the outlook period, with the majority of production growth occurring between 1992 and 1997.

The direction of these results is robust across the sensitivity analyses carried out in this study. In the cases employing a smaller resource base in the province and/or higher resource costs, both productive capacity and utilization of transmission facilities in the province are significantly taxed in the near-term, with substantial growth occurring in the mid-1990s. **This suggests that the current upstream activity within northeastern British Columbia is both justified and likely to continue for some time.**

Turning to market access, the analysis suggests significant growth in exports from British Columbia, especially when capacity is made available to move gas supplies directly into the California and Rocky Mountain regions in the U.S. **These two transport corridors represent over half of the increase in British Columbia production between 1992 and 1997.** These flows, together with the roughly 100 Bcf per year flow via Gordondale, represent about 250 Bcf per year or about one third of the 1997 production level projected for British Columbia in this analysis. **The optimism in this study regarding**

Figure 1

British Columbia Natural Gas Production and Wellhead Prices



SOURCE: CERI, September 1990.

British Columbia gas sector development is, therefore, heavily conditioned upon the availability of these three transportation options at the assumed levels of capacity.

Without the additional flows via these three transportation links, one is left with a more moderate outlook for British Columbia gas production, based upon normal growth in the domestic market, an increment coming from initiation of service to Vancouver Island, and a growing market share in the Pacific Northwest region of the U.S., British Columbia's traditional export market. **Based upon the analytical work carried out in this study, such moderate growth is quite certain. The potential for substantial growth thus lies in significantly expanding flows to extra-provincial markets beyond those currently supplied by British Columbia gas.**

The transportation process made available to move British Columbia gas directly to California resulted in the delivery of supply to the California border at a competitive price in all time periods. **It is therefore recommended that the option of moving British Columbia supply to California via Northwest Pipeline and PGT warrants further analysis, when more complete cost information becomes available.**

Two key uncertainties underlying these results represent a framework for further analysis and research into British Columbia gas supply potential. These relate to uncertainty surrounding the size of the ultimate potential resource base in northeastern British Columbia, and uncertainty surrounding the costs associated with various levels of future potential or undiscovered reserves.

These uncertainties apply not only to the British Columbia resource base, but to the other supply regions represented in the model and, most important to this study, to the Alberta and Rocky Mountain regions. While some work has been carried out in this area by Westcoast and others, substantial additional research is required to more conclusively analyse such issues as the potential for British Columbia supplies to compete with Alberta supplies in export markets, and the potential for flows into Alberta via the Gordondale lateral for delivery to markets east and south.

Finally, the analysis of export market potential for British Columbia gas supplies rests critically on the cost and timing of incremental export capacity to link the province into the Rocky Mountain

supply region and/or the California market directly. As formal proposals for these transmission options are brought forward, it will be useful to readdress the analysis undertaken in this study, in order to more accurately gauge the competitiveness of British Columbia natural gas supplies in the North American continental natural gas market.

Chapter 1

INTRODUCTION

1.1 Purpose of Study

Activity and interest in the search for natural gas in British Columbia have increased dramatically in the past couple of years. This has occurred at a time when activity in many other areas has been modest. The growing momentum in upstream activity and the significant success of this activity is now being reflected in the pursuit of new markets for British Columbia's natural gas resources. This resurgence is evidenced by the record throughput volumes on the Westcoast Energy Inc. (Westcoast) pipeline system of 412.5 Bcf in 1989, an increase of 25 percent over 1988 levels. The previous record throughput had been 411.9 Bcf, established in 1973.

The level of current activity in British Columbia naturally raises questions regarding the longer-term outlook. This study seeks to contribute to an understanding of the recent activity in British Columbia and the fundamentals underlying the longer-term outlook for the natural gas sector of that province's economy.

In October of 1989, the Canadian Energy Research Institute (CERI) published Study No. 32, *Continental Natural Gas Market, Canadian Export Capacity in the 90s*. Results of this research showed much promise for British Columbia and it became apparent that a further and more detailed evaluation of the outlook for the natural gas industry in British Columbia was warranted.

Building upon the insights gained in Study No. 32, the primary objective of this study is to examine several factors which will shape the gas industry in British Columbia in the long term and determine the markets in which British Columbia gas will compete. These factors include the nature of the resource base, transportation possibilities and institutional constraints.

The modelling tool employed is the North American Regional Gas (NARG) model developed by Decision Focus Inc. This model is in widespread use within North America for the evaluation of long-term natural gas markets. Because of its network structure, the NARG model permits simultaneous consideration of supply and demand interactions within and between regions of North America. This is vital, as developments in other regions will

impact markets for British Columbia's natural gas. The NARG model also captures interfuel competition between natural gas and fuel oil in the non-core sectors of its various demand regions.

A second objective of this study is to provide background on the unique development of the natural gas industry in British Columbia. This component of the study will serve to put the analytical findings into a proper perspective, given the environment in which the industry has developed to date and the environment within which it is likely to develop in the future.

1.2 Study Outline

The study is organized as follows. Chapter 2 reviews the historical background surrounding the exploitation of natural gas in British Columbia, together with recent institutional developments in British Columbia which will influence the future development of the natural gas industry.

Chapter 3 provides a brief overview of the NARG model and the modifications made for this study. This chapter also includes a discussion of the limitations of the model results. Chapter 4 presents and discusses the model results. This is followed by recommendations in Chapter 5.

Appendix A contains detailed output for the various cases and Appendix B contains some of the key inputs for both the reference case and the alternative scenarios discussed in Chapter 4. A description of the NARG model is included in Appendix C. Further model documentation is available from Decision Focus Inc.

Chapter 2

BACKGROUND OF THE BRITISH COLUMBIA NATURAL GAS INDUSTRY

2.1 Historical Background

2.1.1 Foundation of the Natural Gas Industry in British Columbia

At December 31, 1988, cumulative natural gas production in British Columbia had reached 7.135 Tcf. This flow of energy to market began with the commencement of service on the Westcoast Energy Inc. (Westcoast) pipeline from Fort St. John, British Columbia, on October 1, 1957. The establishment of the resource base to support the Westcoast project can be traced to the November 1951 discovery of natural gas at Fort St. John in the Peace River area of northeast British Columbia. The Fort St. John discovery, the largest in Canada to that time, sparked an exploration boom in the area. Canadian and American companies took out exploration permits covering 30 million acres in the surrounding area. Resulting natural gas discoveries led Westcoast to propose a pipeline to serve markets in southwestern British Columbia and the U.S. Northwest.

While exploration activity in northeast British Columbia continued, Westcoast sought to supplement its supply in British Columbia with nearby supplies from the Peace River area of Alberta. In April 1952, the Alberta Legislature granted Westcoast a permit authorizing it to remove gas from the northwest area of the province for a period of twenty years. This was based on the finding that the northern Alberta gas would not be essential for future use in the markets of southern Alberta and, except for local communities in northwestern Alberta, was surplus to Alberta's needs. A proviso in the export permit stipulated that Westcoast would provide gas service in the Grande Prairie region, in return for the removal permit.

Natural gas supplies in southern Alberta were not in competition with British Columbia supplies for service in the Pacific Northwest and British Columbia markets. This was due to a ruling by the Oil and Gas Conservation Board of Alberta which, in effect, committed these supplies to eastern Canadian markets.

With the southern Alberta supplies of natural gas committed to particular markets, and the northern Alberta supplies available to Westcoast, the focus of the competition to serve markets on the Pacific coast altered. This was most clearly observed in the shift in plans of the Pacific Northwest Pipeline Corporation (Pacific Northwest). Pacific Northwest was originally seeking to move gas from southern Alberta to markets on the Pacific coast. This was also the group intending to serve eastern Canadian markets with supplies from the Texas Panhandle area. Pacific Northwest, in light of the above decisions in Alberta, abandoned its two original proposals and proposed a 1400 mile pipeline to connect natural gas supplies in the San Juan Basin to Spokane, Portland and Seattle, with an extension to Vancouver.

With two major projects set to serve the Pacific coast markets (Westcoast and Pacific Northwest) the matter went to hearing before the Federal Power Commission (FPC) in the United States. In June of 1954 the FPC dismissed the Westcoast application and granted Pacific Northwest authorization to serve the U.S. Northwest region with an extension to Vancouver. This decision posed a serious threat to the viability of the Westcoast proposal since the market available within British Columbia was not sufficient to warrant construction of such a pipeline. Development in northeast British Columbia was similarly threatened.

Ultimately, proponents of the Westcoast proposal succeeded in bringing about a compromise agreement. In early January of 1954, prior to the decision of the FPC in June of that year, Westcoast management had commenced the planning of a direct link from British Columbia to California. El Paso Natural Gas Company of Texas (El Paso), which at that time was exclusively serving California, supported this proposal on the basis that gas supplies in northeastern British Columbia warranted such a project. In addition, Westcoast filed an appeal to the U.S. courts succeeding, for a time, in rendering Pacific Northwest incapable of financing its pipeline. This move, along with pressure from California interests seeking to preserve the San Juan field for their own future use and rapid demand growth in the U.S. Northwest region, led the sponsors of the Pacific Northwest proposal to approach Westcoast with a compromise.

Negotiation subsequently led to an agreement whereby Pacific Northwest would construct its proposed pipeline from the San Juan Basin to the U.S. Northwest region and purchase 200 MMcf/d of

gas from Westcoast at Sumas, British Columbia. Further, El Paso, through exchange on Pacific Northwest, would purchase 100 MMcf/d from Westcoast, taking delivery in the San Juan Basin area. The proposal was approved by the United States FPC on November 25, 1955. Construction of the Pacific Northwest pipeline from the San Juan was completed less than a year later, with temporary service to Vancouver until completion of the Westcoast project on October 1, 1957. The Westcoast system had an initial capacity of 400 MMcf/d and a single gas processing facility at Taylor, British Columbia. It is useful to point out here that the natural gas gathering, processing and transmission infrastructure in British Columbia was designed and built around large central processing facilities. Figure 2.1 provides a diagram of the current Westcoast system.

In support of the initial Westcoast project, contracts were also signed with the two domestic utilities, the British Columbia Electric Company (British Columbia Electric) and the Inland Natural Gas Company Ltd. (Inland). These domestic volumes were substantially smaller than the export commitments, with Inland agreeing to purchase 21 MMcf/d initially and 27 MMcf/d commencing in 1960, and British Columbia Electric also agreeing to purchase 21 MMcf/d initially, increasing to 50 MMcf/d in 1960. The domestic price included a demand charge of $3.21 per Mcf plus a commodity charge of 20 cents per Mcf, and matched Pacific Northwest's proposed resale prices to various communities in the United States. Westcoast's price to Pacific Northwest was based on Pacific Northwest's price to its United States customers.

Under these arrangements, Pacific Northwest paid less for natural gas purchased from Westcoast at the international boundary than was being paid by British Columbia Electric and Inland.[1] This price disadvantage to the Canadian distributors continued until a second export contract was signed in 1966 with El Paso (which had merged with Pacific Northwest since the initial agreement). The effect of the new contract with El Paso, and new contracts with the domestic distributors at the same time, was to remove the differential between Canadian and export sales by creating approximate equality between the price to British Columbia Hydro (formerly British Columbia Electric) and El Paso, and a price advantage to Inland, whose gas was transmitted over a shorter distance on the Westcoast system to markets in the British Columbia interior.[2]

Figure 2.1
Westcoast Energy Inc.
Pipeline Systems Map

2.1.2 Development of the Physical Infrastructure

By 1957, sufficient supplies had been discovered in southern and central Alberta that Pacific Gas and Electric Co. put forward a proposal to move Alberta gas southwest into Westcoast's traditional market areas of Washington, Oregon and Idaho and to move any surplus gas on to California. Westcoast, before the Oil and Gas Conservation Board of Alberta and the National Energy Board (NEB), contended that Alberta gas should not be allowed to jeopardize future development of the industry in British Columbia by taking away market share in Westcoast's market area. In turn, Westcoast proposed that only 150 MMcf/d of Alberta gas be allowed to enter Westcoast's Pacific Northwest market area, with the balance of the area's Canadian gas requirements to be met with supplies from British Columbia. Agreement was reached in 1959 that Westcoast would have a share in the Alberta to Kingsgate, British Columbia pipeline and export the 150 MMcf/d from Alberta as a limited volume. The remaining 400 MMcf/d were to be delivered directly to California from Alberta.

Using the 150 MMcf/d from Kingsgate, Westcoast was able to offset proposals in the United States to add facilities to increase volumes of San Juan gas into the Pacific Northwest market area. This was especially to Westcoast's benefit in that it became clear that significant supply could soon be brought on from the Fort Nelson area in British Columbia to meet market requirements in the Pacific Northwest market area.

In 1964, Westcoast applied for permission to extend its system north to Fort Nelson, British Columbia; build gathering facilities; add compression on its existing mainline; and build a 200 MMcf/d processing facility at Fort Nelson, the first major addition to the physical infrastructure in the province.[3] Construction of these facilities was approved and completed in 1965. The Fort Nelson line enabled Westcoast to offer 100 MMcf/d of additional gas to markets in Washington, Oregon and Idaho through the contract with El Paso.

In March of 1967, Westcoast received approval for further system expansion, mainline looping, additional compression, and expansion of the Fort Nelson processing facility to 530 MMcf/d of raw gas capacity.[4] These facilities were largely intended to increase capacity at Huntingdon for exports to El Paso. However, all but two loops, constructed immediately to ensure adequate service to Canadian customers in the 1967 to 1968 contract year, were delayed due to the refusal of the FPC to authorize the import of the additional 200

MMcf/d of gas by El Paso associated with this application. The basis of the refusal was the pricing agreement between Westcoast and El Paso. It was not until 1970 that a pricing agreement, the "Fourth Service Agreement" between Westcoast and El Paso, was approved by the FPC applying to the full export volume of 809 MMcf/d. The NEB conditioned the accompanying export licence (GL-41) such that the export price be set at 105 percent of the comparable Canadian sale price at Huntingdon.[5] Significant expansion of export capacity has not occurred since that approved in January of 1972 to meet the 809 MMcf/d requirement of the Fourth Service Agreement.[6]

Besides infrastructure development to serve export markets, significant developments were also undertaken to service markets within British Columbia. When the FPC failed to authorize El Paso to import gas from Westcoast in 1967, Westcoast was faced with the prospect of contractual obligation to purchase substantial take-or-pay volumes deliverable by gas producers in 1969 and 1970 which had been intended to service the U.S. market. Also at this time, several projected industrial ventures were announced in the area from Prince George to Prince Rupert, the significant remaining area of British Columbia not yet served with natural gas. Under the above circumstances, Westcoast established a new subsidiary, Pacific Northern Gas Ltd. (Pacific Northern), to serve residential, commercial and industrial markets in the Prince George area and the west coast ports of Prince Rupert and Kitimat. Westcoast agreed to deliver the volumes required for Pacific Northern's market at a discounted price for five years, after which the discount was to be offset by a premium over a number of years. Due to the failure of key industrial projects in the area, Westcoast continued to assist Pacific Northern financially into the 1970s to enable it to serve the slowly growing residential, commercial and small industrial sectors in its market area.

Domestic demand-driven expansion of the Westcoast system continued throughout the 1970s and early 1980s, including looping additions to Westcoast's mainline system, approved by the NEB in July of 1973 and July of 1980.[7] A request to add additional mainline looping was denied by the NEB in its decision of June 1978.[8] Westcoast expanded its gathering and processing facilities to support the mainline expansion. The more recent projects of significance occurred in the late 1970s and include the Grizzly-Bullmoose-Sukunka project, the Silver-Dahl project and the Junior-Sierra project.

The Grizzly-Bullmoose-Sukunka project, approved in January 1978, consists of a raw gas gathering pipeline from the project

area, with laterals, and a processing plant at Pine River. The distinguishing feature of the Grizzly-Bullmoose-Sukunka project is the sour nature of the gas supply. Initial capacity of the Pine River plant was 265 MMcf/d of raw gas processing capacity producing approximately 200 MMcf/d of marketable gas. Pipeline facilities from the plant to the mainline were built with a capacity of 395 MMcf/d to carry future production from pools that had yet to be discovered.[9]

The Silver-Dahl project was also approved in January 1978, involving an extension of the gathering system in the area north of the McMahon processing facility at Taylor. The design capacity of the Silver-Dahl project was 64 MMcf/d of raw gas.[10] Both the Grizzly-Bullmoose-Sukunka project and the Silver-Dahl project were supported by forecasted growth in domestic demand. The Junior-Sierra project was supported by projections of domestic and export market growth. The Junior-Sierra project involved tieing the Junior, Ekwan, Sierra and Sahtaneh areas into the Fort Nelson processing facility.[11] The design capacity of the Junior-Sierra project was over 200 MMcf/d.

Little expansion occurred on the Westcoast system through the 1980s. As shown in Table 2.1, mainline throughput volumes on the Westcoast system were very low relative to design capacity, particularly in the mid-1980s. The recovery in throughput volumes in the late 1980s is expected to continue into the 1990s (see Table 2.2).

Although the Westcoast system is not currently operating at full capacity, bottlenecks do exist. To allocate the capacity formerly used to accommodate export sales which became available November 1, 1989, Westcoast held an open season during which priority to capacity was given to existing shippers demonstrating either a firm market or a firm supply, rather than on a first come first served basis. Section 2.2.2 outlines the circumstances surrounding this export capacity becoming available. Since the open season, capacity at the processing facility near Taylor, British Columbia has been fully contracted. At time of writing, hearings had been completed on a Westcoast proposal to expand this facility (the McMahon Plant) to increase its capacity to 620 MMcf/d from the current 530 MMcf/d of marketable gas. Unocal Canada Limited and Westcoast are developing a storage site at Aitken Creek in northern British Columbia to enable fully-processed gas to be stored in the summer and withdrawn in the winter to permit enhanced utilization of the upstream facilities.

TABLE 2.1

WESTCOAST MAINLINE NATURAL GAS THROUGHPUT

	1989	1988	1987	1986	1985
Export (Bcf)					
Natural Gas Sales	47.5	57.3	118.2	90.1	91.3
Gas Transported For Others	125.9	80.1	20.5	12.7	7.6
	173.4	137.4	138.7	102.8	98.9
Domestic (Bcf)					
Natural Gas Sales					
B.C. Gas Inc. (incl. Inland)	148.4	116.9	118.0	131.1	145.3
Pacific Northern Gas Ltd.	27.1	29.9	29.4	22.3	26.4
Others	2.6	2.4	2.4	5.6	3.6
Gas Transported For Others	53.4	35.1	23.7	6.6	–
Gas Storage	7.6	10.4	–	–	–
	239.1	194.7	173.5	165.5	175.4
TOTAL	412.5	332.1	312.2	268.3	274.3
Average Daily Throughput (MMcf/d)	1.130	0.907	0.855	0.735	0.751
Designed Throughput Capacity (MMcf/d)	1.502	1.502	1.502	1.502	1.502
Export Capacity (MMcf/d)	0.823	0.823	0.823	0.823	0.823

SOURCE: Westcoast Energy Inc.

TABLE 2.2

WESTCOAST CAPACITY UTILIZATION

	Capacity (Bcf)		Utilization (%)	
	January and February	Annual	January and February	Annual
1988[a]	90	525	82	63
1989[a]	90	525	90	79
1990[b]	90	525	91	82
1991[b]	90	525	91[c]	86[c]

SOURCE: NEB, *Natural Gas Market Assessment 1989-1991*, October 1989.

[a]Actual.
[b]Forecast.
[c]Volumes for the Pacific Coast Energy Corporation project not included.

Expansion of the Pine River processing facility is being discussed for 1991.

2.1.3 Resource Base Development

British Columbia is Canada's second largest natural gas producing area after Alberta. To date, only about 7000 wells have been drilled in northeastern British Columbia with less than 100 wells drilled outside the portion of the Western Canadian Sedimentary Basin (WCSB) which lies in northeastern British Columbia. The small number of wells drilled in northeastern British Columbia yields a low drilling density relative to that in the portion of the WCSB located in Alberta, which has a drilling density four and a half times larger. Other differences exist between the resource bases in British Columbia and Alberta. A large portion of British Columbia's remaining reserves are in a relatively small number of large pools. According to the NEB, almost three quarters of British Columbia's established gas reserves are contained in some 190 pools, each with initial reserves of at least 11 Bcf.[12] Further, the average initial pool size in British Columbia is almost 14 Bcf. By comparison, the average initial pool size in Alberta is just over 5 Bcf. Reserves of British Columbia's largest pools are given in Table 2.3.

TABLE 2.3

BRITISH COLUMBIA'S LARGEST GAS POOLS

Pool Name	Remaining Reserves (Bcf)	Proportion of Total B.C. Reserves (%)
Yoyo	401	5.3
Laprise Creek	232	3.1
Sierra	206	2.7
Monias	204	2.7
Nig Creek	140	1.8
Jedney	108	1.4
TOTAL	1291	16.5

SOURCE: B.C. Ministry of Energy, Mines and Petroleum Resources.

Yoyo and Sierra were the two largest producing fields in 1988, producing 39 and 35 Bcf of marketable gas, respectively. These two pools accounted for 24 percent of British Columbia's 1988 gas production.

In any given region, increased depth is generally indicative of greater geological age. A further difference between British Columbia and Alberta is that a large proportion of British Columbia's reserves are located in the Jurassic to Pennsylvanian geological zones at intermediate depth. In Alberta, the largest proportion of reserves are of the younger Cretaceous age, shallower and of a much smaller average pool size. Generally, reserves of natural gas in British Columbia are of a larger average size and at greater depth than in Alberta. Recent exploration activity is expected to increase Lower Cretaceous reserves in British Columbia.

Another significant difference between British Columbia and Alberta is the nature of the unconnected established reserves. In Alberta, it is estimated that over 8.5 Tcf of unconnected reserves, representing about 18 percent of Alberta's remaining reserves, are contained in over 8,000 pools.[13] Over half of these unconnected reserves are in pools with less than 3.5 Bcf of initial reserves, with an average pool size of less than 1 Bcf. These reserves are rather well distributed throughout the province. On the contrary, almost two-thirds of the shut-in reserves in British Columbia are contained in pools larger than 3.5 Bcf in size, with an average initial pool size of about 4 Bcf. The implication here is that the unconnected resource in British Columbia may be easier to tie in to the gas system, relative to the situation in Alberta. Table 2.4 provides estimates of unconnected gas reserves in British Columbia by processing facility. The two largest accumulations of unconnected reserves are the Tommy Lakes and Ojay pools, containing 218 and 201 Bcf of marketable gas, respectively. Tommy Lakes is 120 miles north east of the McMahon plant in Taylor. Ojay is located 90 miles southwest of the Pine River plant.

Results from recent exploration have given rise to much optimism regarding the resource base in British Columbia. Of late, drilling activity has been directed toward several areas of interest. One such area is the "Ring-Border" area located near the British Columbia/Alberta border. This area is attractive because of the potential for multiple pay zones and good rates of production from relatively shallow resources. Other areas of interest include the "Deep Basin" area, such as the Bullmoose and Sukunka fields, where the potential for large pool size and high producibility make these prospects particularly attractive. The Fort St. John area has also seen significant activity, mainly to maintain deliverability on existing declining reserves, as has the Jean Marie formation in the Helmet and July Lake areas where low risk drilling (due to the blanket nature of the

TABLE 2.4

UNCONNECTED GAS RESERVES BY PLANT
(Bcf)

Plant	Marketable Gas
Fort St. John	1003
Fort Nelson	568
Pine River/Elmworth	717
North Foothills[a]	406
Other[b]	131
Total	2824

SOURCE: B.C. Ministry of Energy, Mines and Petroleum Resources.

[a]Includes: Pocketknife, Cypress, Grassy, Adsett, Sikanni.
[b]Includes: Fort St. John Bypass, Boundary Lake Trunkline.

TABLE 2.5

NATURAL GAS WELLS DRILLED
1980-1989

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Total Gas Wells	218	96	41	19	31	41	36	45	41	85

SOURCE: B.C. Ministry of Energy, Mines and Petroleum Resources.

sand) and relatively low transportation costs form the major attraction for drilling activity.

The current level of activity is significant in comparison to the relatively low levels of activity during the 1980s, as shown in Table 2.5.

There were 166 oil and gas wells drilled in the first three months of 1990, representing a 66 percent increase over the similar period of 1989. The British Columbia Ministry of Energy, Mines and Petroleum Resources (MEMPR) estimates that as much as 90 percent, or about 150 wells, were directed toward gas objectives.

2.1.4 Development of the Institutional Framework for Natural Gas in B.C.

The physical pipeline infrastructure as it has developed has, to a significant degree, shaped the prospects for British Columbia's natural gas industry over the past thirty years. Similarly, and also to a significant degree, the natural gas industry in British Columbia has been influenced by the institutional framework governing its activity. Public regulation of the natural gas industry has varied significantly in emphasis. The following is a brief overview of the development of the institutional setting surrounding the natural gas industry in British Columbia. The objective, as with the previous discussion of the development of the physical infrastructure, is to provide a context in which past activity and historical trends in the industry can be compared to projections regarding the future of the industry.

When Westcoast began operations in 1957, it purchased all gas within the province. Westcoast negotiated purchase prices with producers, then resold the gas to utilities in southern British Columbia and into the export market. The resale price was negotiated between Westcoast and its sales customers, with Westcoast retaining the margin between the negotiated purchase price and the resale price of the gas. In 1973, the Government of British Columbia established the British Columbia Energy Commission to assess the situation at that time. Several factors led to this assessment, including an inability on the part of Westcoast to meet its contract demand due to technical difficulties encountered in particular supply fields, beginning in 1972. Westcoast asked for a sharing of the shortfall between domestic and export customers. Also, producers were exerting pressure to receive higher prices for their supplies. The recommendation forthcoming

from the Commission was that a crown corporation be established to secure gas supply and provide it to Westcoast.

In November of 1973, the British Columbia Petroleum Corporation (BCPC) was established. At this time, Westcoast entered into an agreement (the "BCPC Agreement") with the BCPC under which all of its British Columbia gas purchase contracts were assigned to the BCPC. In turn, the BCPC agreed to supply Westcoast with all of its British Columbia gas requirements to the extent that natural gas from British Columbia was required to meet Westcoast's domestic and export sales commitments.

Under the agreement, Westcoast retained the functions of gathering, processing and transporting the gas and selling it to the various domestic utilities and export customers. For the domestic utilities, Westcoast sold gas at a wholesale price set for each utility by the British Columbia Cabinet upon the recommendation of the British Columbia Utilities Commission (BCUC). Export prices were determined according to federal and provincial energy policy regulations of the time, with NEB approval on a licence-by-licence basis.

From the proceeds of natural gas sales, Westcoast retained its cost of service, including a return on its rate base. The balance of the proceeds was remitted to the BCPC. The BCPC then deducted the payment to the producers and its administrative costs and remitted the net amount to the Provincial Treasury. The payment to producers was termed the 'net field price' and was set by the British Columbia Cabinet based on a formula recommended by the BCUC.[14] Producers were not required to pay royalties or the costs of processing and transporting gas. All sulphur and natural gas liquids extracted during the processing of raw gas were owned by the BCPC, which was given responsibility for the sale of these by-products.

In 1982, a study group led by Dr. G. W. Govier was established by the British Columbia Minister of Energy, Mines and Petroleum Resources to investigate and report on a number of issues concerning the marketing of British Columbia's natural gas. Early in 1983, the "Govier Report" was submitted to the provincial government which, in turn, released a document entitled "A Report on the Marketing of British Columbia's Natural Gas - Decisions and Comments". The government document identified areas in which the recommendations of the Govier study group had been accepted for action, areas in which the Govier study group recommendations would

not be accepted, and areas in which the government would seek written comments from interested parties before making a decision.

Stemming from the recommendations of the Govier group and other parties, the B.C. government approved, in principle, the following (September 1983 and July 1984):

(a) a wholesale pricing policy which tied the price of natural gas to the price of crude oil at the refinery gate at Vancouver;

(b) a netback system for establishing the field price of natural gas;

(c) that the BCPC was no longer to be the sole purchaser of natural gas in British Columbia;

(d) that direct sales between producers and end-users were permitted;

(e) that Westcoast was to act as a contract carrier and processor for future contracted gas; and

(f) that producers were to be given the option of building their own gathering, processing and transportation facilities.

In July of 1985, the formal implementation of a number of the decisions announced in September 1983 and July 1984 was carried out by way of the Natural Gas Price Act. The key features of the Natural Gas Price Act were:

(a) the establishment of a field price for natural gas paid to producers in British Columbia on a netback basis by deducting the appropriate cost of service from the system average wholesale price;

(b) the establishment of an explicit royalty system for natural gas producers;

(c) the institution of an export flowback arrangement that was to allow all producers to share in the benefits accruing from the export market; and

(d) permission for producers to engage in direct sales between themselves and parties other than the BCPC.

These changes in policy resulted in the amendment of all BCPC gas purchase contracts, in order to comply with the new Natural Gas Price Act. Under this new legislation, the BCPC no longer

fulfilled the role of a collector of an implicit royalty but, instead, paid the total revenues (less a cost of service) received by it from the sale of gas and by-products to its producers, who then paid the province for its royalty share of production.

With regard to allowing direct sales, producers were still required to transact with the BCPC for royalty purposes but could engage in direct sales with end use customers. However, such direct sales were really only possible on new sales, given the National Energy Board's policy of prohibiting self displacement on the Westcoast system. This is discussed further in the next section.

Aside from the regulatory environment within British Columbia, federal jurisdictions in Canada and the United States influence exports of British Columbia's natural gas supplies, either directly or indirectly. Perhaps the major regulatory change directly impacting Westcoast was the National Energy Board's decision in 1985 to change Westcoast's toll methodology.[15] This involved a fixed toll which was to include demand and commodity components, versus the previous variable cost toll which varied from month to month depending on incurred costs. Also, as mentioned, initiatives have been taken over the past several years by the NEB to reduce the regulatory restrictions on the export of Canadian natural gas supplies, moving to what the NEB refers to as the Market-Based Procedure used in the export approval process. The latest development on this front has been the dropping of the Benefit-Cost Criteria for exports in which it was necessary for exporters to demonstrate that their export project provided a net benefit to Canada.[16] Another issue before the NEB, which at time of writing remained unresolved, is that of incremental versus rolled-in toll methodology for pipeline expansion.

Within the United States, movement to a more competitive and market based system of regulation has also taken place. The impact of this change upon flows of British Columbia natural gas has been significant. On June 10, 1988, Northwest Pipeline Corporation accepted an open access certificate under the Federal Energy Regulatory Commission's (FERC) Order 500. In accepting the open access certificate, Northwest Pipeline allowed its customers to convert up to 100 percent of their firm sales contract demand to transportation demand. Northwest Pipeline's customers responded with very large conversion to transportation, leaving Northwest Pipeline with greatly reduced requirements for Canadian gas and leading to a declaration of force majeure under Article XIV of the Fourth Service Agreement with Westcoast.[17] Under the Fourth Service Agreement, Westcoast was to

deliver 809 MMcf/d to Northwest Pipeline at Huntingdon, British Columbia.[18] This agreement was amended in 1987, reducing Northwest Pipeline's contract demand from 809 MMcf/d to 550 MMcf/d. Following the declaration of force majeure by Northwest Pipeline, a settlement was reached between Northwest Pipeline and Westcoast in which Northwest paid Westcoast $11 million ($Cdn)--the sum of the unpaid demand charges for October through December 1988--and 75 percent of the demand charges applicable to export capacity not taken up between January and October 1989, after which time the Fourth Service Agreement expired.

Other FERC initiatives have also influenced British Columbia's export markets. FERC Order 256, the as-billed ruling, continues to result in an increase in the commodity charge on Canadian gas supply to various U.S. pipelines. Northwest Pipeline is one of these pipelines and thus the cost of British Columbia gas, to the extent that volumes flowing are less than capacity (and they have been), will be higher to Northwest Pipeline than in the absence of Order 256. The result has been a negative impact upon British Columbia's exports of natural gas.

2.2 Recent Market Developments

2.2.1 Domestic Markets

A number of recent decisions regarding regulation and infrastructure development will have a significant impact upon domestic natural gas markets in British Columbia in the future. In terms of infrastructure development, the agreement reached between Pacific Coast Energy Corporation (Pacific Coast) and the Federal and Provincial governments will result in the initiation of natural gas service to Vancouver Island. This pipeline, to be built and operated by Pacific Coast at a cost of about $280 million ($1989 Cdn), is expected to increase natural gas consumption in British Columbia by up to 10 percent. Pacific Coast will serve residential, commercial and industrial customers on Vancouver Island and coastal areas northwest of Vancouver. Currently, the project is scheduled to be completed in September 1991 and has been incorporated into the representation of British Columbia domestic demand for this study.

From a regulatory perspective, decisions by the National Energy Board concerning capacity allocation on Westcoast and the issue of self displacement on Westcoast are of significant importance in terms of their influence upon the domestic natural gas market in British Columbia. The capacity allocation issue has to do with the

allocation of the capacity on Westcoast which is currently used to accommodate sales of BCPC gas by Westcoast to BC Gas Inc. (BC Gas).[19] This capacity is currently held by BC Gas but the sales contracts are set to expire on October 31, 1991. When being reviewed by the NEB last year, discussion centred on which party, if any, should have priority access to this capacity when it becomes available in 1991. This issue arose, according to the NEB, because Westcoast took the position that neither BC Gas nor the BCPC have pre-emptive rights to the capacity when the sales contracts expire and, further, Westcoast wished to discontinue its gas sales role.[20]

In discussion leading to the NEB's decision on this matter, various parties provided argument focussing upon the following:

(1) the need to provide for an equal opportunity for buyers and sellers to gain market access;

(2) the need to recognize that historically the capacity has been used by BCPC and BC Gas and to provide them with an opportunity to negotiate a settlement on the allocation of the available capacity; and

(3) the need to ensure that security of supply to the domestic core market is not adversely affected during the transition period.

The decision of the NEB in this matter was to accept Westcoast's proposal that the capacity becoming available November 1, 1991 be reserved for any shipper who could demonstrate the existence of a "ripe deal", namely both a firm market and a firm supply, into the BC Gas market. But the Board changed the date after which a shipper could reserve this capacity to May 1, 1991. The NEB also accepted BC Gas/Inland's proposal that they be given a right of first refusal for any remaining capacity as at May 1, 1991, up to a maximum of their operating demand requirements at that time. In the NEB's view, this would provide an adequate safeguard for the British Columbia core market. Any capacity remaining after May 1, 1991 will be allocated on the basis of the existing queue.[21]

As stated, Westcoast had expressed its wish to discontinue its gas sales role. In its decision of September 1989, the NEB rescinded its policy of prohibiting self displacement on the Westcoast system effective November 1, 1991, corresponding to the expiry of the BC Gas sales contracts.[22] The stated objective of this decision is to promote an orderly transition to a market-sensitive pricing regime by November 1, 1991. The decision will also allow Westcoast to operate as a pure transportation entity, minimizing its role in the sale of

natural gas to customers. To the extent that the parties involved renegotiate their contracts prior to this time, the transition can begin sooner. BC Gas has stated that it has begun negotiating long-term supply arrangements with producers.

The effect of the self-displacement decision will be to expand the already active direct sales market. The recent growth in direct sales in the British Columbia domestic market is shown in Table 2.6 below.

TABLE 2.6

DIRECT SALES IN THE
BRITISH COLUMBIA MARKET
(Bcf)

	1985	1986	1987	1988	1989 (est.)
Volume of Sales	0.0	6.0	21.4	43.0	58.6

SOURCE: National Energy Board, *Natural Gas Market Assessment 1989-1991*, October 1989.

2.2.2 Export Market

As discussed, Northwest Pipeline declared force majeure under the Fourth Service Agreement with Westcoast in 1988. Westcoast subsequently introduced an interim policy to allocate the 550 MMcf/d of capacity formerly used to accommodate sales to Northwest Pipeline. This capacity was, at that time, taken up by the "550 shippers" (comprised of the BCPC and several producers). An open season was held to allocate the former Northwest Pipeline capacity which would become available on November 1, 1989. The NEB, in its decision with preliminary reasons of July 1, 1989, set the allocation hierarchy to be employed in the open season. Essentially this involves giving priority to existing shippers who were serving the export market at that time, and who could demonstrate either a firm market or a firm supply. Henceforth, capacity allocation will take place based upon the queuing procedures as set out in the NEB's September 1989 decision, with renewal rights for firm shippers that can demonstrate a firm gas supply or a firm market.[23] This framework of having a queue with renewal rights for firm shippers will govern capacity allocation on the Westcoast system for the foreseeable future.

At the present time, much of the export flow occurs on a short-term, interruptible basis. The impact of the changes of the last

three years can be seen by looking back to Table 2.2 which shows, among other things, the dramatic change in export sales by Westcoast to gas transported for others in export markets. Westcoast still holds gas export licences, as detailed in Table 2.7, but Westcoast's export sales ability is set to decline significantly in the near future.

2.3 Pending Institutional Developments

As the past institutional framework has shaped historical activity in the natural gas industry, so the future institutional framework and its evolution over time will also greatly influence industry activity. The difficulty in accounting for the future influence of regulatory activity in the natural gas industry is that government policy changes through time. Given this, it is necessary to view any projections in light of the current environment, and with expectations of future change.

A common practice in dealing with the future regulatory environment under which business will take place is to assume that the current regulatory environment will remain unchanged or, alternatively, that it will change through time toward a particular end. Presently, it would appear that the latter is the more realistic approach in that regulators in Canada and the U.S. have stated their intention to move the natural gas industry toward greater competition. As this process continues at both the federal and provincial levels, markets at given points in time will reflect the regulatory progress. Recently, significant policy and regulatory changes have begun to occur in British Columbia which the British Columbia government hopes will greatly increase reliance on market forces. These recent initiatives are outlined below, including the BCPC privatization and proposed new policy governing removal of natural gas from the province.

2.3.1 British Columbia Petroleum Corporation Privatization

On May 15, 1990, the British Columbia Cabinet approved the transfer of the marketing operations of the British Columbia Petroleum Corporation (BCPC) to the private sector. The process to privatize the BCPC was initiated in 1987 when the Government of British Columbia entertained proposals for the privatization of BCPC's marketing operations. On June 1, 1988, the Government of British Columbia accepted the proposal of Pacific Gas Marketing subject to successful negotiations for the privatization. Pacific Gas Marketing

TABLE 2.7

LICENCES TO EXPORT NATURAL GAS AT HUNTINGDON AS AT DECEMBER 31, 1989

Exporter	Licence or Order Number	Point of Export	Term of Licence or Order		Maximum Volumes		
			From	To	Daily (MMcf/d)	Annual (Bcf)	Term (Bcf)
Amoco Canada Petroleum Co. Ltd.	GL-112	Huntingdon	1989-07-24	1989-10-31	24.8	2.48	136.12
			1989-11-01	2004-10-31	24.8	9.07	
Westcoast Energy Inc.	GL-93[a]	Huntingdon, B.C.	1989-11-01	1992-10-31	300.0	109.5	492.8
			1992-11-01	1993-10-31	225.0	82.1	
			1993-11-01	1994-10-31	150.0	54.7	
			1994-11-01	1995-10-31	75.0	27.4	
	GL-94[a]	Huntingdon/Kingsgate, B.C. & Monchy, Saskatchewan combined maximum	1989-11-01	1990-10-31	484.7	163.7	327.2
			1990-11-01	1991-10-31	322.8	109.0	
			1991-11-01	1992-10-31	161.4	54.5	
		Maximum permitted at Kingsgate, B.C. as part of combined Huntingdon/ Kingsgate/Monchy volumes	1989-11-01	1990-10-31	100.0	36.5	
			1990-11-01	1991-10-31	100.0	36.5	
			1991-11-01	1992-10-31	100.0	36.6	
		Maximum permitted at Monchy, Saskatchewan as part of combined Huntingdon/ Kingsgate/Monchy volumes	1989-11-01	1990-10-31	50.0	18.3	
			1990-11-01	1991-10-31	50.0	18.3	
			1991-11-01	1992-10-31	50.0	18.3	

SOURCE: National Energy Board.

[a]Since December 31, 1989 GL-93 and GL-94 have been consolidated into GL-131, issued in the name of Westcoast Energy Marketing Limited. GL-131 relates to deliveries to Northwest Pipeline at Kingsgate, B.C. and Northwest Natural Gas Co. at Huntingdon, B.C.

subsequently submitted a more detailed revised proposal to the Government. This revised proposal involved the use of a British Columbia company for the acquisition, CanWest Gas Supply (1989) Ltd. (CanWest), a company incorporated by the producer group for the acquisition. The producer group includes Amoco Canada Petroleum Company Ltd., Canadian Hunter Exploration Ltd., Czar Resources Ltd., Mobil Oil Canada, Petro-Canada Inc., Unocal Canada Ltd., Wainoco Oil Corporation, and others. These companies represent approximately 60 percent of the attributed daily volume of gas supply under firm contract to BCPC. Petro-Canada Inc., the largest shareholder, represents 36 percent of CanWest. Negotiations ended in a formal agreement on May 10, 1990 which was approved by the British Columbia Cabinet and the BCPC Board of Directors.

As mentioned, the transfer is structured such that the BCPC's existing regulatory functions are left with BCPC. The transfer to CanWest will include:[24]

(a) Approximately 775 natural gas and by-product purchase agreements that BCPC has with approximately 140 producers.

(b) Natural gas and by-product sales contracts with various customers including:

(i) The natural gas sales/purchase agreement between the BCPC and Westcoast Energy Inc. which supplies Westcoast's resale contracts with BC Gas Inc., Pacific Northern Gas Ltd. and off-line utilities (the "Basic Agreement");

(ii) The natural gas sales/purchase agreement between BCPC and Northwest Natural Gas Company (the "Northwest Natural Agreement");

(iii) Various short-term domestic and export sales contracts and arrangements;

(iv) The natural gas liquids sales/purchase agreement between the BCPC and Amoco Canada Petroleum Company Ltd. (the "Shallow Cut Agreement");

(v) The Taylor NGL Plant - BCPC agreement among BCPC, Petro-Canada Ltd. and Westcoast (the "Deep Cut Agreement");

(vi) Sulphur sales/purchase agreements between BCPC and Petrosul International Ltd. (the "Petrosul Agreement");

(c) Gathering, processing and transportation agreements with Westcoast (the "Service Agreements");

(d) The marketing services agreement between BCPC and Westcoast Energy Marketing Ltd.; and

(e) Other marketing related agreements and assets including any deferred revenues, BCPC's office lease and other fixed assets, and other corporate and employee related contracts.

The Acquisition Agreement was closed on July 31, 1990, its conditions having been met. Conditions in the agreement included:

(a) CanWest completing, to its satisfaction, an investigation of the assets and business being acquired and there being no material and adverse change in the business between the date of signing the acquisition agreement and closing.

(b) A minimum of thirty producers, representing an aggregate of 60 percent of the attributed daily volume under firm contract to BCPC, agreeing to a novation of their gas purchase agreements from BCPC and amending their gas purchase agreements to provide for netback pricing.

(c) A minimum of ten producers, representing an aggregate of 40 percent of the attributed daily volume under firm contract to BCPC, subscribing for Class B shares in CanWest.

(d) The following agreements described above being novated or assigned from BCPC.

(e) Section 1 and Parts 2 and 3 of the *Natural Gas Price Act*, S.B.C. 1989, c. 74 and Regulations thereunder satisfactory to CanWest being proclaimed into force and effect.

(f) CanWest receiving satisfactory opinions from its counsel as to the consequences of the proposed transaction under the *Competition Act* (Canada) and U.S. anti-trust laws.

Several elements have been outlined which will serve to govern CanWest's operations.

CanWest will act as a not-for-profit aggregator of British Columbia produced natural gas and will serve domestic and export markets. Sales revenues will be aggregated across sales and flowed back to producers on a netback basis after subtracting CanWest's costs of operation. Producer approval of CanWest's resale prices will be required as set forth in the Natural Gas Price Act (S.B.C. 1989, c. 74).

Also included in the Company's articles are provisions to ensure that CanWest's Board of Directors and management will be independent and at arm's length from the Company's producers and consumers. Through holding a special share in the Company, the British Columbia government will ensure that the principal office of CanWest remains in British Columbia, that general meetings be held in British Columbia, that the agreed restrictions on the Company's business are adhered to, that the Government retain the right to appoint one director, that the President and Chief Executive Officer be a resident of British Columbia, and that the Government retain control over sale of CanWest's undertaking, continuation into another jurisdiction and voluntary liquidation.

This change from a publicly controlled marketing organization to a privately held company is likely to have a significant impact on the marketing of British Columbia's natural gas supply, especially since a very large portion of British Columbia's resources have been marketed through the BCPC. One should expect a significantly more aggressive marketing effort in British Columbia.

2.3.2 Proposed Policy Changes

The Government of British Columbia has proposed a number of changes to British Columbia's natural gas removal policies. The key initiatives as proposed by the British Columbia Ministry of Energy, Mines and Petroleum Resources are as follows:[25]

(a) Elimination of the Mandatory Surplus Test.

(b) Evaluation, audit and monitoring of committed and available lands and reserves, production, deliverability and markets to which reserves are dedicated.

(c) Elimination of the Border Price Test.

(d) Implementation of the Natural Gas Market Information System and the exercise of British Columbia Utilities Commission prudence of purchase reviews.

(e) Institution of a Complaints Procedure for domestic gas consumers.

(f) Flexible reserves dedication with a minimum reserve requirement of 50 to 100 percent established reserves.

(g) Industry access to the Ministry's inventory of committed and available lands and established reserves.

(h) Parallel terms in both export and domestic markets. The maximum term is currently fifteen years but terms in excess of fifteen years may be permitted in unique circumstances.

(i) Monthly reports of gas removal volumes and prices at the removal point (border) and the plant inlet. Monthly reporting will terminate upon implementation of the Natural Gas Market Information System.

(j) Institution of a Minimum Price for royalty purposes.

(k) No reserves dedications for short-term Energy Removal Certificates (ERC). However, reporting of well location and field name will be required.

(l) A levy on all gas sales to recover the cost of ERC administration and domestic supply protection.

The British Columbia government states that "the intent of these proposed policy changes is to put more emphasis on market forces, freeing British Columbia gas buyers and producers to follow commercial trends and, with the new 'access to information' system, make sure that there is increased competition in the market."[26] Thus, the stated objectives of the policy changes as outlined appear to follow the general trend in other jurisdictions toward market deregulation.

On October 9, 1990, the British Columbia government announced its intention to implement the above policy with some modification.[27] The minimum royalty price was introduced for a one year trial period with further evaluation, the complaints procedure was referred to a government industry task force for further study, and the flexible reserves dedication policy was to be detailed subsequently. The revised policy was to take effect on November 1, 1990.

Footnotes

[1]Canada, National Energy Board, *Reasons for Decision in the Matter of the Application, Under Part IV of the National Energy Board Act Rates Application - Phase I of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, May 1978).

[2]Ibid.

[3]Canada, National Energy Board, *Report to The Governor in Council in the Matter of the Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, July 1964).

[4]Canada, National Energy Board, *Report to The Governor in Council in the Matter of the Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, March 1967).

[5]Canada, National Energy Board, *Report to the Governor in Council in the Matter of the Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, August 1970).

[6]Canada, National Energy Board, *Report to the Governor in Council in the Matter of the Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, January 1972).

[7]Canada, National Energy Board, *Report to the Governor in Council in the Matter of the Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, July 1973).

[8]Canada, National Energy Board, *Reasons for Decision in the Matter of an Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, July 1980).

[9]Canada, National Energy Board, *Reasons for Decision in the Matter of an Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, January 1978).

[10]Ibid.

[11]Canada, National Energy Board, *Reasons for Decision in the Matter of an Application Under the National Energy Board Act of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, May 1979).

[12]Canada, National Energy Board, *Natural Gas Market Assessment, 1989-1991* (Ottawa, Ontario: Minister of Supply and Services Canada, October 1989).

[13]Ibid.

[14]For more detail see: British Columbia, Ministry of Energy, Mines and Resources, *A Report on the Marketing of British Columbia Natural Gas*, Prepared by Govier, G.W. (Victoria, British Columbia: Queen's Printer for British Columbia , February 1988).

[15]Canada, National Energy Board, *Reasons for Decision in the Matter of the Method of Regulation of the Tolls of Westcoast Transmission Company Limited* (Ottawa, Ontario: Minister of Supply and Services Canada, April 1985).

[16]This most recent development in the Market Based Procedure is discussed in Canada National Energy Board, *Reasons for Decision, Review of Certain Aspects of the Market Based Procedure*, GHW-4-89 (Ottawa, Ontario: Minister of Supply and Services Canada, 1990).

[17]In total 1.14 Bcf/d or 78 percent of Northwest Pipeline's sales contract demand of 1.45 Bcf/d was converted to firm transportation upon accepting the open access certificate.

[18]Under the Kingsgate Agreement, Westcoast was to deliver 152 MMcf/d to Northwest Pipeline at Kingsgate, British Columbia. Both the Fourth Service Agreement and the Kingsgate Agreement were authorized under gas licence GL-41 (which permitted volumes of 284.8 Bcf/yr) which, in any case, expired October 1989.

[19]In 1988 Inland Natural Gas Co. Ltd. bought the B.C. Hydro Mainland Gas Division. The new name of the combined company is BC Gas Inc.

[20]Canada, National Energy Board, *Reasons for Decision Westcoast Energy Inc.*, RH-1-89 (Ottawa, Ontario: Minister of Supply and Services Canada, September 1989).

[21]Ibid.

[22]Ibid.

[23]Ibid.

[24]CanWest Gas Supply (1989) Ltd., *Acquisition of the Marketing Operations of the British Columbia Petroleum Corporation, Executive Summary* (Vancouver, British Columbia: CanWest Gas Supply (1989) Ltd., May 1990).

[25]British Columbia Ministry of Energy, Mines and Petroleum Resources, "British Columbia Natural Gas Removal Policy:

A Policy Paper" (Victoria, British Columbia: Ministry of Energy, Mines and Petroleum Resources, May 1990).

[26]British Columbia Ministry of Energy, Mines and Petroleum Resources, "Davis Releases New B.C. Natural Gas Policy," Press Release (Victoria, British Columbia: Ministry of Energy, Mines and Petroleum Resources, May 31, 1990).

[27]British Columbia Ministry of Energy, Mines and Petroleum Resources, "Long Term Energy Removal Certificate Policy Review for Natural Gas," Information Letter E90-16 (Victoria, British Columbia: Ministry of Energy, Mines and Petroleum Resources, October 1990).

Chapter 3

FRAMEWORK FOR ANALYSIS

3.1 The Analytical Framework

This study made use of the North American Regional Gas (NARG) model, an application of the Generalized Equilibrium Modelling System (GEMS) developed by Decision Focus Inc. (DFI). In the NARG model, process submodels are used to describe the activities of production, transmission, distribution and consumption of natural gas. A network then links the process models together to represent the spatial relationship between various demand and supply regions. In the NARG model, the transmission and distribution processes do not necessarily model individual pipelines or distribution systems but, instead, model pipeline corridors between various supply and demand regions or, in the case of distribution, aggregate distribution in a particular region.

The process models in GEMS consist of a set of mathematical relations that describe physical, behavioural and financial interactions. For the NARG model, the parameters of the generic GEMS process models represent the specific model activities; resource supply, conversion (transportation and distribution are represented in this manner), market allocation and end-use demand. The NARG model is solved in an iterative manner, yielding a solution of equilibrium prices and quantities through time in all of the activities represented in the model. Here, equilibrium implies a situation in which all the physical and behavioural process relations in all of the network's activities are simultaneously satisfied, within some specified limit of tolerance.

The GEMS system has a number of intuitively appealing solution characteristics. On the supply side of the framework, prices and quantities in supply regions lie exactly on the wellhead supply curves in these regions. Therefore, the solution satisfies the supply relationships for all primary resource supplies represented in the network. Similarly, prices and quantities in the demand regions lie exactly on the demand curve and therefore the solution satisfies the demand relationships for all end-users in the network.

Solutions also have the characteristics that all required revenue calculations hold across all processes in the network in a bottom to top consecutive order (from supply to demand) and that all thermal efficiency calculations hold across all processes in a top to bottom consecutive order (demand to supply). The implication is that the quantities of gas from each source add up to the correct total at points of competition and that dollars spent on gas in each market add up to the correct total. The prices and quantities of any given solution are the only ones that simultaneously satisfy the above characteristics.

The NARG model is well grounded in economic theory. Some of the particulars of the NARG model are discussed further in Appendix 3. At this point, however, it will be useful to note certain key characteristics which should be recognized when interpreting model results. First, the NARG model assumes competitive market behaviour. Therefore, solution prices and quantities balance the self-interests of all agents represented in the network and economic efficiency (the most widely accepted measure of economic welfare) is maximized, as theory would suggest.

Second, prices offered to consumers in a given region by competing supply sources in the model are identical and the price is equal to the cost of the next, or marginal, unit that could be delivered by any of the suppliers. That is, in the solution, price equals marginal cost and marginal cost is equal for all competing suppliers at a particular point of competition (referring to the offer price to the purchasing distributor). If this is not the case, the model will adjust until this result occurs. Therefore, it is the price that sets the market share of competing sources, implying that market share is a direct outcome of the solution. **One must bear this in mind when relating model results to a world in which natural gas marketing is based to a large degree upon contracts**. In actuality, one would expect contracts to impose constraints upon the market shares of various supplies. This may not be respected in this model.

Third, the NARG model employs the concept of rational expectations in its representation of producer behaviour. Producer behaviour in the model is represented in a Hotelling-style framework whereby the producer chooses a production schedule to maximize the net present value of the profit accruing from this production over time. This implies that a knowledge of future prices is necessary and, in its simplest form, this representation assumes that not only are producers' expectations rational, they are also correct (i.e., perfect foresight)

regarding the future schedule of prices. This implies that an assumption regarding a given variable in a particular time period impacts on all time periods.

For the purposes of this study, some modifications were made to the NARG model, as received from Decision Focus Inc., both to the network and to the data. These specific changes are outlined in the next section, with the remainder of this section providing the data sources for the NARG model in general. The particular NARG model which formed the starting point for this study was that received from Decision Focus Inc. in March of 1990, containing all enhancements and updates made by Decision Focus Inc. and users of the model to that point. **Specific questions about this version of the model should be directed to Decision Focus Inc.**[1]

The NARG model begins its calculations from a base year balance of flows on the various links within the model. The base year in the NARG model is 1987. Initial year energy flows for this year are based upon Energy Information Administration statistics for the U.S. and National Energy Board information for Canada.

Input parameters for the network's collection of process models can be grouped into three general areas. First, the model requires supply data in the form of reserves of natural gas resources, future potential natural gas resources and the costs associated with various levels of resource. For the United States, the Potential Gas Committee (PGC) estimates of April 1987 form the basis of the future potential estimates incorporated into the model.[2] Revision has been made by DFI, however, to various regions in the model as deemed necessary in light of better information.

The cost-resource relationships associated with the resource data were constructed by Geological Exploration Associates for DFI. Levels of reserves and ultimate potential for the various resource areas represented in the model are provided in Table 3.1.[3] The resource estimates used in the model are of natural gas which can be recovered by conventional means given adequate economic incentives and using current or foreseeable technology.[4] A number of categories of natural gas resources are used in the PGC estimation. In this study, the "most likely" levels of future discoveries as estimated by the PGC were utilized in the NARG model.

The levels of resource and costs of resource data inputs for the United States, as specified in the NARG model, were not scrutinized for the purposes of this study, as such an exercise was not within

TABLE 3.1

REFERENCE CASE - NATURAL GAS SUPPLY ASSUMPTIONS BY REGION (Tcf)

Supply	Remaining Established Reserves (1986)	Cumulative Reserve Additions
North Alaska	10.00	98.36
South Alaska	5.82	17.42
San Juan	6.97	16.79
Rocky Mountains (Shallow)	8.90	68.20
Rocky Mountains (Deep)	1.30	40.50
Northern Great Plains (Shallow)	1.15	20.14
Northern Great Plains (Deep)	10.00	4.00
Anadarko (Shallow)	21.60	71.60
Anadarko (Deep)	11.55	85.94
Permian (Shallow)	12.43	33.10
Permian (Deep)	0.88	25.00
North Central	2.50	16.00
Appalachian (Shallow)	4.36	24.02
Appalachian (Deep)	10.00	15.00
Atlantic Offshore	10.00	15.00
Onshore Lousiana	11.10	4.10
Onshore South Texas	27.70	5.80
Arkoma Onshore	13.52	11.40
Southeast Gulf Onshore	6.00	3.00
Gulf of Mexico Onshore (Deep)	10.00	47.00
Gulf of Mexico Offshore (Shallow)	47.30	62.80
Gulf of Mexico Offshore (Deep)	10.00	32.00
Southern California (Onshore)	2.88	5.70
Southern California (Offshore)	1.00	6.82
Northern California (Onshore)	1.54	6.00
Pacific Northwest	0.34	4.00
British Columbia	7.50	35.50
Alberta	52.50	70.00
Saskatchewan	5.10	4.50
Northern Canada (Onshore)	15.00	75.00
Northern Canada (Offshore)	15.00	10.00
Eastern Canada	1.50	13.50

SOURCE: Canadian Energy Research Institute.

the scope of the study. Levels of resource for the various areas in Canada were based upon 1988 NEB data. These curves were modified by CERI for CERI Study No. 32.[5] Basically, the changes made by CERI reflect a more optimistic outlook with respect to the Canadian natural gas resource base than is reflected in the NARG model as received. Changes made with respect to the British Columbia resource base for this study are outlined in the next section.

The second set of input parameters concern the transportation and distribution of natural gas on all the links in the model. Much of this information as it is found in the NARG model is based upon information compiled by Benjamin Schlessinger and Associates for the California Energy Commission concerning transmission costs, capacities, efficiencies, etc. As with the supply input, Decision Focus Inc. has modified the transportation and distribution representations where appropriate, taking advantage of better information as it became available. Further, aside from the existing natural gas transmission network, several of the currently proposed pipeline projects have been incorporated into the model framework based upon the parameters specified by the particular project sponsors in their latest filings. Costs and capacity parameters are provided in Appendix A for the portion of the model network of most relevance to this study.

Finally, the NARG model user must specify appropriate parameters to represent the demand for natural gas in North America. The source of this information for the NARG model generally is the Gas Research Institute (GRI) for the United States and the National Energy Board for Canada. Essentially, the user specifies a demand level and corresponding price--referred to as a 'reference quantity and price pair'--for each demand region represented in the model in each period of the model. In other words, a demand and price projection is specified for each demand region in the model. The NARG model uses these price/quantity pairs as a reference point in each time period. By specifying price elasticities for each demand region, the user can permit movement away from the reference quantities and prices specified by using the elastic demand option of the model. Price elasticities input for U.S. and Canadian demand regions were assumed to be constant across consuming regions and to represent the response of total gas demand within a region to a change in the average gas price. Elasticities used were generally 0.10 as a short-run elasticity and 0.60 as a long-run elasticity. Reference quantity-price pairs as specified in the model are provided in Table 3.2. The source of the demand data for the United States for this study was the "1989 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010". Data were input

TABLE 3.2

REFERENCE CASE - REFERENCE DEMAND AND PRICE PAIRS BY REGION

	1987				1992				1997			
	Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)	
	core	non-core[a]	core	non-core[a]	core	non-core[a]	core	non-core[a]	core	non-core[a]	core	non-core[a]
South Alaska	0.19		1.20		0.21		1.23		0.21		1.27	
Pacific Northwest	0.17	0.06	1.72	1.93	0.13	0.17	2.12	2.30	0.13	0.21	2.53	2.67
WNC/Mountain	1.54	0.58	3.59	2.82	1.60	0.39	3.68	2.78	1.62	0.40	4.35	3.27
West South Central	2.06	3.60	2.16	2.11	2.86	2.96	2.70	2.55	2.93	3.12	3.26	3.05
East North Central	2.51	0.59	3.52	2.65	2.53	0.56	4.11	2.94	2.44	0.65	4.72	3.39
East South Central	0.49	0.28	3.12	2.46	0.52	0.24	3.61	2.68	0.53	0.28	4.17	3.06
South Atlantic	0.82	0.82	4.20	2.77	0.96	1.07	4.75	2.79	1.00	1.51	5.34	3.14
Mid-Atlantic	1.32	1.02	5.23	2.89	1.46	1.26	5.89	2.84	1.43	1.21	6.52	3.20
SoCal Gas Co.	0.43	0.44	4.95	2.29	0.54	0.41	5.51	2.75	0.59	0.52	6.12	3.20
PG&E Co.	0.33	0.46	4.50	2.40	0.41	0.44	4.88	2.69	0.45	0.55	5.52	3.19
SDG&E Co.	0.05	0.07	4.38	2.43	0.06	0.07	4.93	2.80	0.06	0.08	5.52	3.22
EOR California	0.20		2.30		0.19		2.45		0.23		2.90	
New England	0.27	0.09	6.65	2.97	0.33	0.21	7.36	2.78	0.36	0.22	8.04	3.19
Western Canada	0.77	0.02	2.44	1.59	0.96	0.02	2.92	2.17	1.07	0.03	3.55	2.80
Eastern Canada	0.13	0.05	3.65	2.85	0.18	0.06	4.20	3.40	0.20	0.07	4.92	4.12
Ontario	0.55	0.15	3.31	2.26	0.64	0.17	3.84	2.79	0.69	0.18	4.54	3.49
British Columbia	0.19	0.00	2.63	1.88	0.27	0.01	2.65	1.90	0.31	0.01	2.99	2.24

(Continued on Next Page)

TABLE 3.2 (Continued)

	2002				2007				2012			
	Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)		Demand (Tcf)		Price ($)	
	core	non-core[a]	core	non-core[a]	core	non-core[a]	core	non-core[a]	core	non-core[a]	core	non-core[a]
South Alaska	0.22		1.34		0.23		1.44		0.24		1.56	
Pacific Northwest	0.13	0.25	3.17	3.19	0.14	0.29	3.79	3.88	0.17	0.27	4.77	4.82
WNC/Mountain	1.64	0.39	5.06	3.82	1.65	0.45	5.89	4.68	1.68	0.45	6.86	5.77
West South Central	2.99	3.39	3.94	3.63	2.97	3.75	4.72	4.45	3.05	3.89	5.62	5.46
East North Central	2.38	0.79	5.43	3.96	2.30	0.92	6.24	4.85	2.29	0.92	7.19	5.98
East South Central	0.55	0.37	4.85	3.55	0.57	0.45	5.62	4.34	0.60	0.45	6.53	5.36
South Atlantic	1.07	1.86	6.04	3.63	1.15	2.10	6.84	4.46	1.22	2.22	7.78	5.52
Mid-Atlantic	1.42	1.33	7.25	3.70	1.39	1.41	8.08	4.55	1.40	1.44	9.04	5.63
SoCal Gas Co.	0.62	0.62	6.80	3.74	0.63	0.55	7.72	4.60	0.65	0.48	8.84	5.68
PG&E Co.	0.47	0.66	6.19	3.73	0.48	0.58	7.08	4.59	0.50	0.51	8.21	5.68
SDG&E Co.	0.07	0.10	6.19	3.74	0.07	0.09	7.09	4.60	0.07	0.08	8.17	5.68
EOR California	0.28		3.50		0.25		4.39		0.22		5.46	
New England	0.37	0.26	8.80	3.75	0.38	0.29	9.66	4.67	0.39	0.30	10.67	5.83
Western Canada	1.17	0.03	4.18	3.43	1.27	0.03	4.98	4.23	1.39	0.03	6.03	5.28
Eastern Canada	0.21	0.08	5.69	4.89	0.24	0.08	6.60	5.80	0.26	0.09	7.77	6.97
Ontario	0.77	0.20	5.28	4.23	0.85	0.23	6.16	5.11	0.95	0.25	7.30	6.25
British Columbia	0.33	0.01	3.57	2.82	0.35	0.01	4.14	3.39	0.37	0.01	5.06	4.31

SOURCE: Canadian Energy Research Institute.

[a]Includes non-core oil use.

directly into the NARG model by U.S. census region and end-use sector.[6]

Briefly, the 1989 GRI Baseline Projection suggests that, on average, natural gas consumption will grow at a modest rate of 0.7 percent per year in the U.S. over the projection period. GRI's Baseline Projection is underlain by a number of macroeconomic assumptions. Real economic growth in the United States is assumed by GRI to average 2.5 percent per year over the period 1988 to 1995, 2.6 percent per year over the period 1995 to 2000, and 2.3 percent per year over the period 2000 to 2010. Thus, for the period 1988 to 2010, real economic growth in the United States is projected to be 2.4 percent per year on average. Consistent with this projected economic growth path, inflation (as measured by the GNP Implicit Price Deflator) is projected to be 5.8 percent per year between 1987 and 1995, 2.0 percent per year between 1995 and 2000 and -0.9 percent per year between 2000 and 2010 for an average level of 1.9 percent per year over the period 1988 to 2010.

The oil price path employed by GRI in the 1989 GRI Baseline Projection is significantly lower than that used in its 1988 projection. This oil price projection, given in Table 3.3, is the oil price track used in this study.

TABLE 3.3

GRI 1989 BASELINE PROJECTION OF
U.S. AVERAGE REFINER ACQUISITION COST OF CRUDE

Year	Crude Cost ($1990 US)
1986	16.80
1987	20.00
1988	16.20
1995	19.80
2000	22.50
2005	28.00
2010	34.50

SOURCE: Gas Research Institute.

Oil price sensitivities were not conducted in this study, as this would require a reestimation of the demand levels provided by GRI in the 1989 Baseline Projection.

The relatively low oil price track employed by GRI implies a generally low energy price future. This has a differential impact across the various sectors represented in the model. Low energy prices are projected by GRI to have little impact on residential gas demand as rapidly increasing efficiencies in residential equipment and the building stock offset demand growth through new gas using customers. The commercial sector, in contrast, is expected to provide substantial growth in gas demand, despite increased energy efficiencies, due to rapid growth in this sector. Industrial demand is projected to show some growth as well but, as always, this is largely dependent upon the ability of natural gas to compete with low cost oil in this sector. Significant gains in natural gas demand are projected for the electric utility industry, with combined-cycle technology offering a competitive edge in new peaking facilities required to meet growing capacity short falls. Gas demand by sector in the 1989 GRI Baseline Projection is given in Table 3.4 for the United States as a whole.

TABLE 3.4

UNITED STATES GAS DEMAND
BY SECTOR
(Tcf)

	Actual 1988	1995	2000	2010
Residential	4.5	4.6	4.5	4.3
Commercial	2.5	2.7	2.9	3.1
Industrial	7.4	7.4	7.5	7.9
Electric Generation	2.6	2.8	4.0	4.2
Transportation	0.6	0.7	0.7	0.9
Total[a]	17.6	18.2	19.5	20.3

SOURCE: Gas Research Institute.

[a]Includes 0.3 Tcf of "other" gas, primarily SNG from petroleum and miscellaneous gases, and high Btu coal gas, in 1995, 2000, and 2010, respectively.

The 1989 GRI Baseline Projection does not include an estimation of potential incremental demand for natural gas as a result of possible environmental regulations. Uncertainty regarding the form and magnitude of policies to meet environmental goals make their inclusion into an analytical framework quite difficult.

The source for the Canadian gas demand data is the NEB's 1988 assessment of Canadian energy supply and demand.[7] The Canadian economy is forecast to grow, on average, at 2.0 percent per year over the projection period, with price inflation assumed to average 4.0 percent per year. Natural gas demand for British Columbia was modified as described below. The Canadian demand levels used in the study are given in Table 3.2 by region.

3.2 Modifications for the Current Study

The NARG model is very flexible in terms of the users' options in adjusting both the parameters in the individual process models and the network itself. As mentioned in the previous section, the framework was updated for this study to reflect the 1989 GRI Baseline Projection as detailed in Table 3.2. For British Columbia, a demand projection was obtained from the British Columbia MEMPR. This projection, also detailed in Table 3.2, includes the Pacific Coast Energy Corporation (Pacific Coast) project to provide natural gas service to Vancouver Island and was incorporated into the model to reflect a more current view of domestic demand in British Columbia. This is especially important in the context of this study as developments such as the Pacific Coast project would not have been reflected in prior versions of the NARG model.

Other changes of significance include a modification of the supply representation of the resource base in northeastern British Columbia. As received, the NARG model had as an estimate of natural gas reserves plus future potential (undiscovered potential) a level of 16.2 Tcf. This was modified in CERI Study No. 32 to a level of 28.5 Tcf and, as shown in Table 3.1, has been increased further to the level of 43.0 Tcf used in this study. With 6.8 Tcf of cumulative production in northeastern British Columbia to December 31, 1987, the level of natural gas resource assumed in this study for northeastern British Columbia corresponds to an ultimate potential (cumulative production plus established reserves plus future or undiscovered potential) of about 50 Tcf. Some estimates of the ultimate potential natural gas resource in northeastern British Columbia are given in Table 3.5 below.

TABLE 3.5

ULTIMATE POTENTIAL MARKETABLE NATURAL GAS IN NORTHEAST BRITISH COLUMBIA

Source	Average or Most Likely Ultimate Potential (Tcf)
Geological Survey of Canada January 1982	45.5
Province of British Columbia (Govier) May 1982	31.8
Westcoast Energy Inc. June 1989	50.5

SOURCE: Canadian Energy Research Institute.

Consultation with officials from the British Columbia MEMPR, the Geological Survey of Canada and several major northeastern British Columbia producers suggests that a level of 50 Tcf for ultimate potential is a reasonable estimation of the resource base in the northeastern British Columbia area, based on current understanding.

A second issue regarding the representation of the natural gas resource base in British Columbia is the cost associated with the resource. A cost curve is generated for the region by ranking the resources expected to be forthcoming from various sources within northeastern British Columbia according to their expected costs. Such a representation is required as input to the NARG model. More specifically, the resource base within a particular supply region of the NARG model is characterized by a capital cost resource supply curve and an operating cost resource supply curve. The definitions of capital costs and operating costs for the purposes of the NARG model are given as follows:

> Capital Cost Resource Supply Curve: Unit well capital costs as a function of cumulative additions to reserves. Capital costs are to include all fixed costs from exploration through development and initial production associated with bringing a new well on-line, exclusive of taxes, lease payments, royalties and interest on debt (which are added in by the model).

Operating Cost Resource Supply Curve: A well's variable cost (exclusive of taxes) per unit of output, as a function of cumulative additions to reserves.

The NARG model uses these two input curves to derive a marginal cost curve to be used in its decision making processes.[8] It does this by applying a factor to the capital cost to account for taxes, lease payments, royalties and interest on debt, and then adds an operating cost figure to the adjusted capital cost. Note that the cost of processing the natural gas resource is not included in the above definitions, nor is by-product revenue. These factors are currently not included in the NARG model representation in any supply region. The underlying assumption is that gas processing costs are offset by by-product revenues.[9] Other than this, the cost curves represent all costs of bringing marketable gas to the pipeline for transportation. Therefore, input costs are to include gathering costs in addition to the above ground cost of the gas. Units used in the NARG model are expressed in $1987 US/Mcf.

The cost curve input into the model for British Columbia was derived by the British Columbia MEMPR. The marginal cost curve for British Columbia is provided in Appendix B as it was represented in the NARG model for the reference case. Also provided is the marginal cost curve for Alberta as adjusted for the reference case to reflect more similar costs between the two provinces. For connected established reserves, the assumption made throughout the NARG model is that capital costs, as defined above, are sunk costs. Thus, these reserves are represented to be available at the operating cost alone. The operating cost used here is based upon the British Columbia MEMPR's Producer Cost Allowance Survey which represents operating costs associated with dehydration and compression of gas. To this is added the gathering cost to transport the gas to a processing facility, based upon the Westcoast toll. The operating cost associated with the remaining established connected reserves is thereby estimated at $US 0.32/Mcf. As of December 31, 1987 there was 4.8 Tcf of remaining connected gas. This level of remaining connected reserves was made available to the model at the above cost.

Following the remaining connected reserves at December 31, 1987, the unconnected established reserves are made available to the model. These have been estimated at 2.8 Tcf at December 31, 1987. Including an average capital cost required to tie in these reserves of $US 0.17/Mcf (unadjusted), the average supply cost for the unconnected reserves is $US 0.49/Mcf. Half of the unconnected resource is

made available at this cost, the rest being placed in the next step of the curve. The costs associated with the future potential resource in British Columbia are based upon economic modelling carried out by the British Columbia MEMPR.

Finally, the user must specify a reserves-to-production ratio which the model is to maintain as a constant through time. Since all resource regions within the United States have been calibrated to a reserves-to-production ratio of 10, Canadian resources were treated similarly. This was necessary in that specifying a higher initial reserves-to-production ratio for the Canadian resource forces the model to maintain this higher ratio through time. Canadian supplies would therefore be put at a relative disadvantage. In terms of model specification, excess reserves for the Canadian resource regions above the level of reserves required to meet a reserves-to-production ratio of 10 were simply included in subsequent steps of the cost curves at costs equal to their operating cost.

As mentioned, changes were also carried out with respect to the network specification of the model. A figure depicting the portion of the network adjacent to the British Columbia supply and demand nodes of the model and a table of the costs and capacities associated with these links are included in Appendix B.

The objective in making these modifications was to represent flows of British Columbia supplies in more detail and to avoid distortion in the representation of costs of moving these and other supplies. The latter point refers to a difficulty which arises in the model because the price of gas from a particular source passing through a market allocation process is set at the average price of all supplies passing through that particular market allocation. The result is that a particular supply may be marked either up or down in price, depending on its price relative to other supplies going into the market allocation. Thus, links were added to the model to reflect movement of Rocky Mountain supply directly into the southern California utility market and British Columbia supply directly into the northern California and Rocky Mountain regions of the model. The British Columbia to Rocky Mountain transportation processes added to the model might be thought of as representing movement on Northwest Pipeline's system and movement on the Pacific Gas Transmission Company (PGT) system in the case of the California link. Currently, capacity does not exist to physically put gas onto the PGT system from Northwest Pipeline but could easily be made available through the

addition of compression to bring supply on Northwest Pipeline to a pressure sufficient to move it onto the PGT system. These transportation processes are not made available to the model until after 1992.

To reflect the potential for movement of British Columbia natural gas supplies into Alberta and then on to other markets, a market allocation process was added to deal with supplies delivered to the British Columbia/Alberta border. The capacity of this link was modelled at 265 MMcf/d and reflects the maximum expandable capacity of what is called the Gordondale lateral, linking the Westcoast system with the NOVA CORPORATION OF ALBERTA (NOVA) system in Alberta. Links were then added from the allocation process at the British Columbia/Alberta border to points of export from Alberta.

3.3 Limitations of Analysis and Qualifications

The methodology incorporated in the NARG model is based upon assumptions of perfect foresight and competitive market behaviour. Deviations from such behaviour are captured in the model by constraints. Thus, the results presented in the next chapter represent an approximation of reality and reflect the insights and expectations of the analyst. They should, therefore, be considered most valuable for the directional trends which they imply.

Regarding the influence of the analyst upon the model, certain assumptions have been made which should be noted. The flows of natural gas on the various links within the model, including those representing future pipeline expansion, were restricted to existing capacity with penalties applied to flows over capacity. However, the penalties applied by the model are not instituted instantly and thus some flow over capacity at relatively modest penalties is permitted. This is to reflect less costly expansion of transportation capacity through adding compression.

Another area requiring some explanation is the behavioural representation in the market allocation processes. Each market allocation process in the model includes a function which apportions market share among the various supply sources available, based upon relative prices. If the prices of two or more competing sources are equal, then each source will receive an equal share of that particular market. However, differentials in price will result in gradual supply

switching so that the more expensive supply source will continue to receive market share.

The justification for such a behavioural representation is that what the model represents as a uniformly priced, homogeneous supply is in reality comprised of a number of heterogeneous sources of supply, some of which may be delivered to a particular market at a substantially lower price. The share of market accruing to the higher cost resource declines more rapidly as the relative price differential increases.

Thus, even though the average price of a particular supply to an allocation point may be higher, some flow may occur. It is important to be aware of this behaviour of the model when considering flows on links that are relatively small but similar in price to other flows into a particular market allocation.

Footnotes

[1]Contact Decision Focus Inc., 4984 El Camino Real, L
Altos, California, 94022, (415) 960-3450.

[2]Potential Gas Agency, *Potential Supply of Natural Gas*
the United States (Golden, Colorado: Potential Gas Agency, Colorad
School of Mines, April 1987).

[3]The NARG model incorporates a number of sources of nat
ral gas from what are referred to as unconventional sources which a
not, for whatever reason, captured in the PGC estimates. Thes
sources include infill drilling, coalbed methane and tight gas. As wit
CERI Study No. 32, these sources of natural gas have been turned o
in the reference case and the reader is referred to that study for
treatment of potential impacts of incorporating these unconventiona
supplies in the model.

[4]Potential supplies of natural gas as defined by the PG
include all of the undiscovered resources plus the portion of the discov
ered resource that is not included in proved reserves, that is, tha
portion of discovered resource that has not been confirmed by testing
Two other categories of potential supplies exist. The possible potentia
resources are those which exist outside of known fields, but that ar
associated with a productive formation in a productive province. Spec
ulative resources are those resources which are expected to be found i
formations or provinces which have not yet proven to be productive.

[5]L.A. Coad and D.H. Maerz, *Continental Natural Ga*
Market: Canadian Export Capacity in the 90s, CERI Study No. 3
(Calgary, Alberta: Canadian Energy Research Institute, Octobe
1989).

[6]Gas Research Institute, *Baseline Projection Data Book*
1989 GRI Baseline Projection of U.S. Energy Supply and Demand to
2010 (Chicago, Illinois: Gas Research Institute, Winter 1989/1990).

[7]National Energy Board, *Canadian Energy Supply and*
Demand 1987-2005 (Ottawa, Ontario: Minister of Supply and Services
Canada, September 1988).

[8]A detailed explanation of this procedure may be found in
D.M. Nesbitt, et al., *The GRI North American Regional Gas Supply-*
Demand Model (Los Altos, California: Decision Focus Inc., February
1990).

[9]This assumption is reasonable, on average, for conventional
Canadian natural gas resources. See B. Bowers and R. Kutney,
"Trends in Crude Oil and Natural Gas Reserves Additions Rates and
Marginal Supply Costs for Western Canada," *Journal of Canadian*
Petroleum Technology, May-June 1989, pp. 88-94.

Chapter 4

EVALUATION OF MARKETS FOR BRITISH COLUMBIA NATURAL GAS

4.1 Reference Case Projections

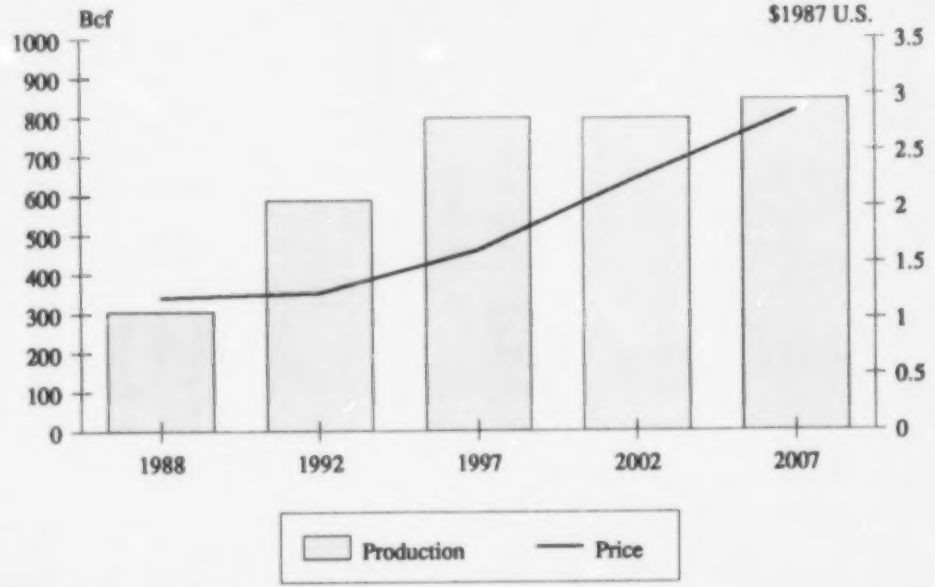
As discussed in Chapter 2, the British Columbia natural gas industry is currently undergoing a significant upturn in activity. Perhaps the most significant contribution of this study can be to comment on whether the underlying market fundamentals argue for continued long-term expansion in the industry. In viewing the results presented here the reader is reminded of the context in which they were generated, as described in the previous chapter, such as the assumptions of unrestricted market competition and perfect foresight. The reader is also reminded that the intention of this work is to take a long-term view based upon the general assumptions outlined in the study. As such, the results may not capture much of the potential variations which will be manifest in the nearer term.

4.1.1 British Columbia Production and Wellhead Prices

The reference case outlook for British Columbia production and average wellhead prices is provided in Figure 4.1. Most striking is the significant growth in British Columbia production over the outlook period. Currently, productive capacity connected to the Westcoast system is estimated to be about 495 Bcf per year from some 500 pools.[1] **Given the projection for 1992 production of about 590 Bcf, significant near-term expansion of productive capacity is required.** With Westcoast's annual mainline capacity for both domestic and export volumes currently at about 525 Bcf per year, the volumes projected for 1992 would require full utilization of Westcoast's mainline capacity by that year, with expansion required thereafter. Given Westcoast's seasonal markets, this average level of utilization will be difficult to achieve. A detailed analysis of the breakdown between various markets, provided below, sheds additional light on the capacity issue.

After 1992, as Figure 4.1 indicates, significant capacity additions will be necessary, both in terms of productive capacity and transmission capacity. As the figure suggests, British Columbia

Figure 4.1
British Columbia Natural Gas Production and Wellhead Prices



SOURCE: CERI, September 1990.

production could reach 800 Bcf per year by the turn of the century with most of this growth occurring between 1992 and 1997. To a significant extent, this growth reflects a growing domestic market. It is also the case that movement of gas out of the province increases through a growing share of the Pacific Northwest market and flows to California. These trends are discussed further below.

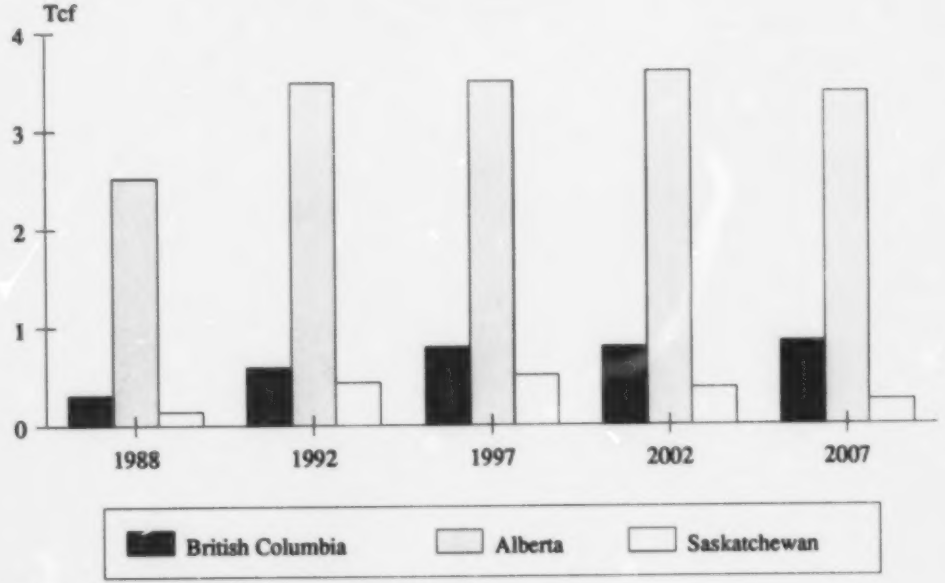
Figure 4.1 also provides wellhead prices for British Columbia corresponding to the production outlook given. Prices increase over time as the resource base matures.

To put the British Columbia results in context, consider Figure 4.2 which contrasts British Columbia production trends with those of Alberta and Saskatchewan. The rapid growth in Saskatchewan production is a result of the proximity of this resource to markets and thus its desirability. The relatively small resource base in Saskatchewan is depleted rather quickly, however, with production falling off after the turn of the century. In reality, this trend will likely be moderated. For Alberta, production also increases substantially by 1992 to meet growth in domestic demand, both in western Canada and eastern Canada, and growth in exports. The results are based on the availability of additional export capacity.[2] Delays in regulatory approvals may delay the production increases forecast for Alberta in 1992.

British Columbia and Saskatchewan production make up virtually all of the growth in production from the Western Canadian Sedimentary Basin over the 1992-1997 time period. The growth in British Columbia production stems principally from increased export sales. What is interesting is that this growth in British Columbia production appears at a time when significant increases in export capacity are made available to Alberta production through the Pacific Gas Transmission Company (PGT) expansion project and the Altamont Gas Transportation Project. However, while export capacity is added from Alberta to meet increased demand in California, the model also chooses to flow British Columbia gas on the links added between British Columbia and the Rocky Mountains (representing expanded flows on Northwest Pipeline) and between British Columbia and California (representing expanded flows on Northwest Pipeline and a physical connection to move this gas onto PGT and then on to California). These results are discussed in more detail in Section 4.1.2.

By the 2002 reporting period, the transition to frontier supply in northern Canada has begun, resulting in the leveling off of

Figure 4.2
Western Canadian Sedimentary
Basin Production



SOURCE: CERI, September 1990.

production in the Western Canadian Sedimentary Basin. This, together with the start of Alaskan gas flows to the south shortly thereafter, results in a decline in Alberta production by 2007. A corresponding decline is not reflected in the level of British Columbia production due mainly to some isolation of the markets for British Columbia's natural gas and the fact that British Columbia production remains competitive well into the next century. To further place the results in context, the reference case outlook for Canadian natural gas production, exports and wellhead prices is provided in Figure 4.3. Canadian production including the northern frontier is expected to grow to the 4.5 to 5.0 Tcf per year range with net exports in the 2.0 Tcf per year range over the outlook period.

The analysis to this point appears to suggest that significant growth will occur in the British Columbia natural gas industry in the coming decades, with the focus of this growth occurring in the mid-1990s. However, before conclusions can be drawn, a more detailed look at the flows underlying this outlook is warranted. This is provided in the next two sections.

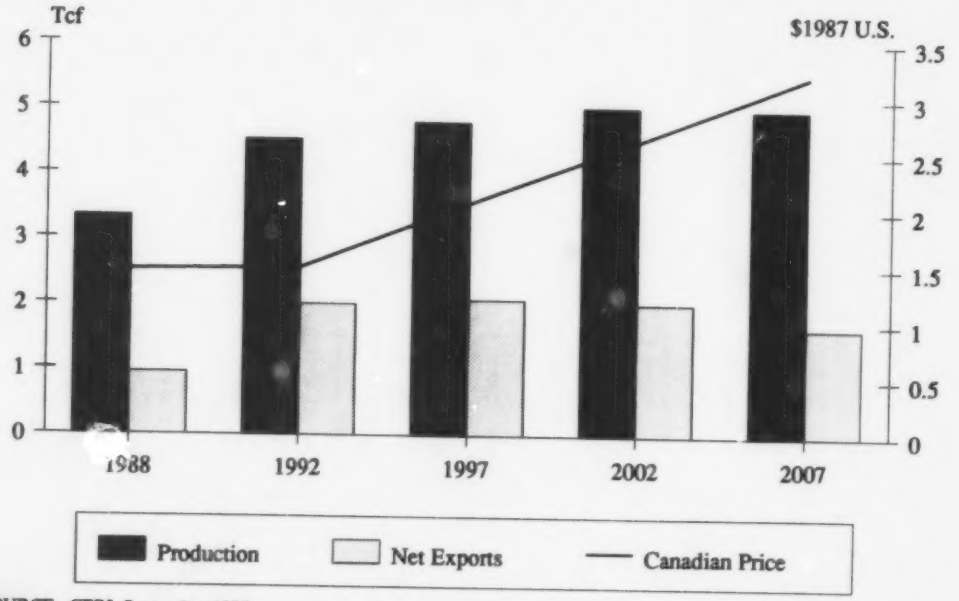
4.1.2 Export Market Outlook

Referring again to Figure 4.3, net Canadian exports in the outlook rise to about 2 Tcf by 1992. This level of net exports is attained as increased export capacity is made available to the model through the Iroquois project and the proposed expansion and extension to the United States Midwest region of the Northern Border pipeline. Net exports increase slowly to 1997 with the growth in total exports from new capacity to California being offset somewhat by increased imports through the St. Clair Pipelines Limited facility into Ontario.

Total British Columbia exports are given in Figure 4.4 along with the border price as determined by the model. The outlook for exports of British Columbia natural gas is optimistic in the longer term. The outlook implies significant expansion of Westcoast's export capacity in the latter half of the 1990s from the current 860 MMcf/d level. Prices, as shown in Figure 4.4, escalate as expected over time as resource costs increase with depletion of lower cost supplies.

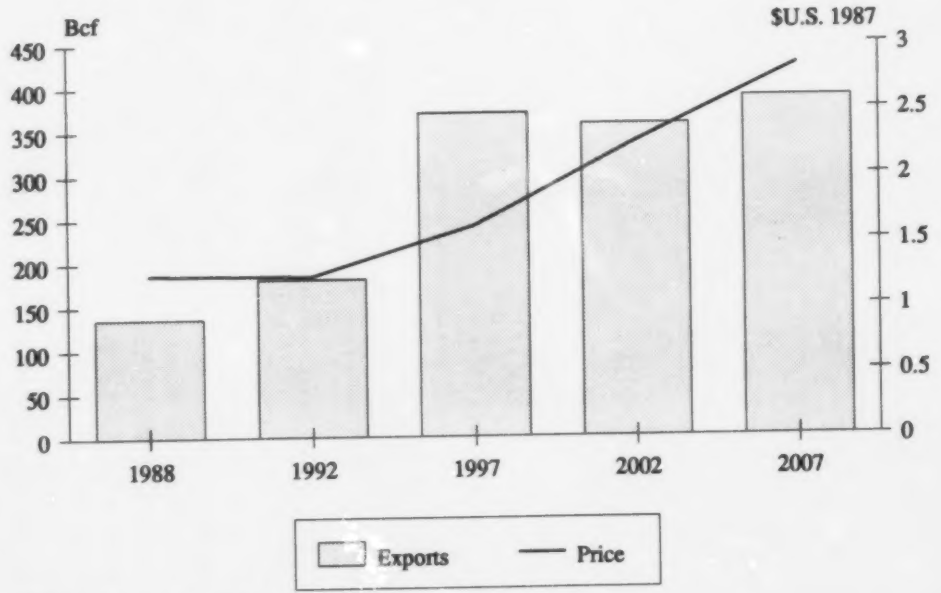
Figure 4.5 provides an outlook for exports of British Columbia natural gas to the Pacific Northwest market. This outlook shows exports to the Pacific Northwest in 1992 of about 180 Bcf, up only slightly from 1989 levels of about 175 Bcf, with a significant increase by 1997. The subsequent decline observed in the flow of

Figure 4.3
Canadian Natural Gas Production
and Wellhead Prices



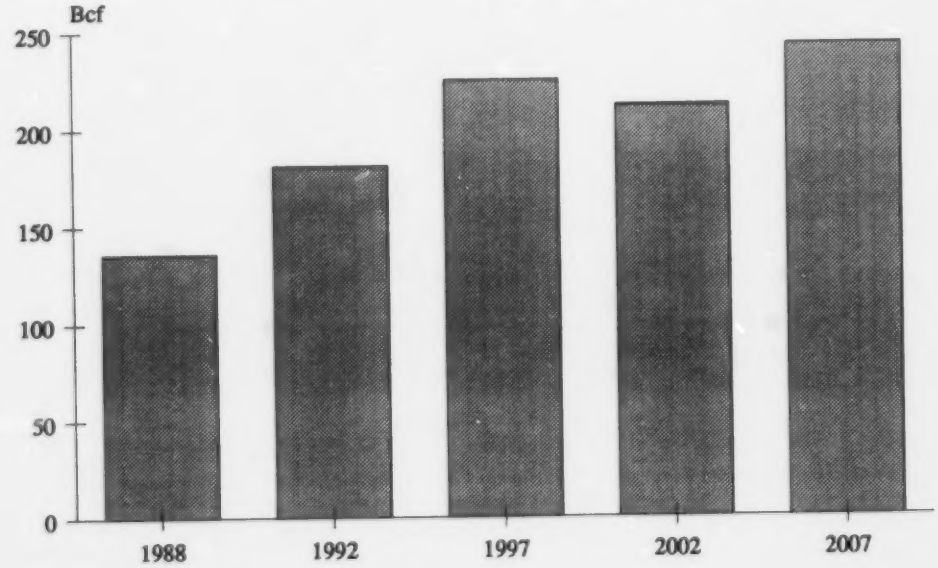
SOURCE: CERI, September 1990.

Figure 4.4
B.C. Exports and Prices via
Huntingdon, B.C.



SOURCE: CERI, September 1990.

Figure 4.5
B.C. Exports to the U.S. Pacific Northwest Market (at Huntingdon, B.C.)



SOURCE: CERI, September 1990.

British Columbia natural gas to the Pacific Northwest market in 2002 is in response to relatively less expensive supply becoming available through the link from Alberta to the Pacific Northwest, as supplies from the northern Canadian frontier depress prices in Alberta. This situation is reversed by 2007 and British Columbia supplies of natural gas regain their competitive advantage and with it their market share in the Pacific Northwest market.

As discussed, these results are dependent upon a number of assumptions regarding behaviour and technical parameters. The issue of importance in the variations in British Columbia's exports to the Pacific Northwest region is the relative resource costs assumed in a number of regions and how these resource costs delivered to this market vary through time. Given the uncertainty regarding such detail, especially future resource costs, it is suggested again that these results be viewed more for their directional indications than absolute magnitudes. With this in mind, we conclude that exports to the Pacific Northwest should exhibit substantial growth over time, to the extent that British Columbia natural gas delivered to the Pacific Northwest market maintains a general competitive advantage relative to other available supply sources.

With these qualifications in mind, we turn to a consideration of the penetration of British Columbia supply into other markets in the United States. As mentioned in Chapter 3, two links were made available to the model to investigate this issue further, one from the export point at Huntingdon to California and one to the Rocky Mountains.

The link from Huntingdon to California represents the possibility of moving British Columbia natural gas on Northwest Pipeline and then onto the PGT system for transport into the California market. In order for such a flow to occur, facility additions will be required. These would likely include expansion on Northwest Pipeline and addition of compression facilities on PGT at the connection with the Northwest Pipeline system to permit the physical movement of natural gas onto PGT from Northwest Pipeline.[3] It must be noted here that no expansion application has been filed by either pipeline to achieve this capability. Making this link available to B.C. gas would likely require a rebalancing of PGT's facilities (north of Stanfield vs south of Stanfield) with its attendant costs. Made available to the model concurrent with the PGT expansion project at a capacity of 73 Bcf per year (200 MMcf/d), flows on this British Columbia to California link reach capacity in the 1997 reporting period and remain at the 73 Bcf level for the remainder of the forecast. Thus, the British Columbia

supply made available to California in this manner is competitive with other available supplies. This is again based upon the relative resource costs as specified in the model and the assumptions regarding the physical facilities comprising this link. Given the representation as outlined, the potential exists to move competitive British Columbia supplies into the California market within the next decade. As further information becomes available regarding possible expansion of Northwest Pipeline and the feasibility of this flow as modelled, more concrete results may be obtained.

The link in the model from Huntingdon to the Rocky Mountain region would also imply some expansion of the Northwest Pipeline system. As with the Huntingdon to California link, no additional costs above the current Northwest Pipeline toll were added at this time. Annual capacity from the Huntingdon export point to the Rocky Mountain region was modelled at 73 Bcf. Flows on this link reach capacity in 1997 and remain at the 73 Bcf level for the remainder of the forecast period. Again, the reader is reminded that these results are dependent upon the specification of the various competing resource bases and their delivered costs to the Rocky Mountain supply region. Note also that flows on this link interconnect with the Kern River pipeline in the Rocky Mountain region. According to current plans, 200 MMcf/d of capacity on that line will be available to B.C. suppliers only until the Altamont pipeline is built, at which time the capacity would be required for supplies delivered via southern Alberta.

For the outlook of substantially increased exports in the latter half of the 1990s and into the early part of the next century to be achieved, capacity additions will be required both on the Westcoast system and, potentially, on transportation facilities south of the border. Regarding expansion of Westcoast facilities, it is presently understood that export capacity could be expanded from 860 MMcf/d to 1060 MMcf/d at very little cost. Under reference case assumptions, the 1060 MMcf/d of export capacity would be approaching 100 percent utilization by 1997. To the extent that plans for expansion of the Northwest Pipeline system materialize, more concrete conclusions may be drawn regarding the viability of the flows to the export markets beyond the Pacific Northwest market at that time.

The remaining out-of-province flow modelled was through what is referred to as the Gordondale lateral, a connection between the Westcoast system and the NOVA system. Detail regarding the network treatment of this connection is given in Appendix B. Flows on

the Gordondale link reach and exceed capacity (97 Bcf per year) by 1992. Again, these flows depend largely upon the relative resource costs in British Columbia and Alberta through time. As represented in the model, the cost of British Columbia supply delivered to Alberta in each time period is lower than the cost of Alberta supply available in the same time period. To the extent that supplies from British Columbia can compete with Alberta supplies going into TransCanada Pipelines, Northern Border or Pacific Gas Transmission, then such flows become attractive.

4.1.3 Domestic Market

Domestic natural gas demand in British Columbia, as represented by the demand forecast provided by the British Columbia MEMPR, shows significant growth. The most substantial increment to demand in the Province in the near term will be the Pacific Coast project to serve Vancouver Island, as described in Chapter 2. In terms of access to other sources of natural gas supply, such as Alberta, British Columbia's domestic market has been rather isolated. In the model representation, a link was included from the Alberta supply region to the British Columbia demand region. This link represents existing capacity of about 80 Bcf per year to move Alberta natural gas supply into British Columbia.

Given the relatively low-cost British Columbia resource base, our analysis suggests that flows of Alberta gas into British Columbia markets would be minimal and would only make sense to the extent that certain of the heterogeneous Alberta supplies can compete on a cost basis with British Columbia natural gas in these markets. However, in this context another issue, that of self-displacement, is of significant importance in determining whether the potential exists for Alberta gas to be sold into British Columbia markets. Under the contractual agreements between the BCPC and Westcoast (the Basic Agreement) and between Westcoast and the British Columbia utilities, the utilities are strictly tied to contracts with Westcoast. This situation may change in the near term as the NEB has decided to permit self-displacement on the Westcoast system with the expiry of the B.C. Gas/Inland gas purchase contracts on October 31, 1991.[4] This would permit utilities in British Columbia to contract for some of their supply portfolio in Alberta.

4.2 Alternative Scenarios

4.2.1 British Columbia Resource Base Sensitivities

To determine the sensitivity of the reference case representation of the natural gas resource base in British Columbia, three alternative resource cases were run using the NARG model. Two of these alternative resource cases concern the total level of natural gas resources believed to exist in northeastern British Columbia and one concerns the costs associated with reserves and future potential natural gas resources. The resource cost curves associated with these alternative cases are provided in Appendix B. Detailed results are provided in Appendix A.

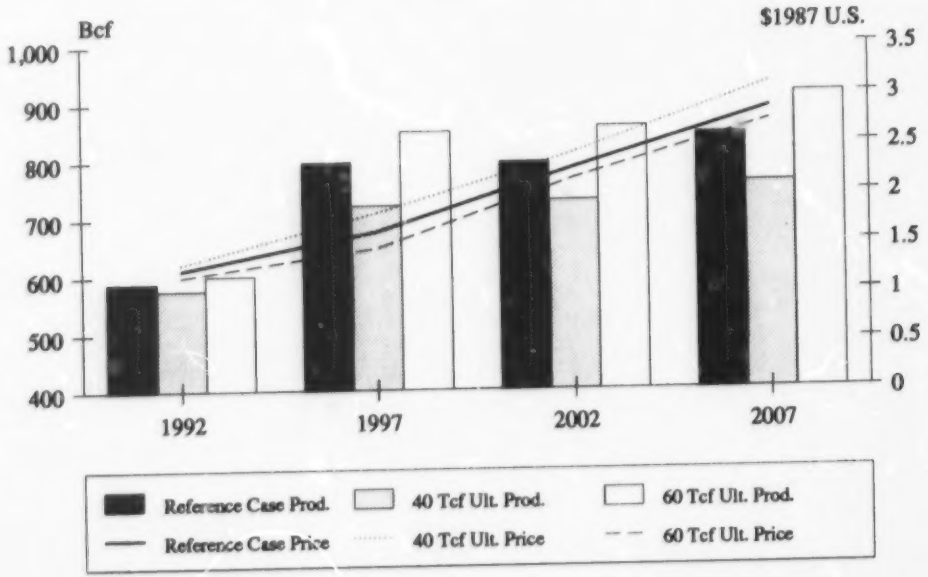
In the case of resource levels, the first alternative tested was to reduce the level of future potential natural gas resources in British Columbia to that associated with an ultimate potential of 40 Tcf versus 50 Tcf in the reference case. Essentially this involved reducing proportionately the level of undiscovered resource available at various costs. The impact, relative to the reference scenario, on British Columbia production and wellhead prices is provided in Figure 4.6. As might be expected, production of British Columbia natural gas is somewhat lower over the outlook period than in the reference case. Corresponding, wellhead prices are slightly higher, also as expected.

Notice here that the only change made in the representation of the resource base in British Columbia was to the level of future potential. Existing established reserves (both connected and unconnected) are not altered between the two cases. However, this change is manifest in the outlook for 1992 production and prices even though production at this time is likely to be mainly from existing reserves. This result stems from the perfect foresight of the NARG model whereby the smaller future potential resource results in a change in near-term behaviour as producers, aware of potentially higher prices in future time periods, alter their production schedules through time. The requirement for capacity additions in the mid to late 1990s, as suggested in the reference case analysis, continues to hold under the low resource scenario.

With respect to flows of British Columbia's natural gas resources to the various markets, the results of employing a smaller resource base for British Columbia are not unexpected. The most significant changes occur in the export levels into the U.S. Pacific

Figure 4.6

B.C. Production and Wellhead Prices
Alternative B.C. Resource Base Scenarios



SOURCE: CERI, September 1990.

Northwest market and on the link introduced from Huntingdon, British Columbia to the U.S. Rocky Mountain supply region. Exports to the Pacific Northwest in this case remain very close to levels achieved in 1989, between 170 and 185 Bcf. Thus all growth in exports is dependent upon the ability to access the California market and move British Columbia supply into pipelines carrying gas into and then south from the U.S. Rocky Mountain supply region. However, with a smaller resource base in British Columbia, the price of British Columbia natural gas delivered in the U.S. Rocky Mountain region is substantially higher relative to the price of gas supplies in the Rocky Mountain region, resulting in a significantly lower flow. With respect to the domestic British Columbia market, a small response in demand is observed over the outlook period associated with the higher gas price profile.

The second resource base scenario involved increasing the level of future potential resources to a level associated with an ultimate potential of 60 Tcf.[5] Again, this was done by altering proportionately the level of the future potential resource available at various costs. As with the lower resource case, this alternative scenario provided results which were largely as expected. As shown in Figure 4.6, the magnitude of the impacts on production volumes and wellhead prices, while opposite in direction, are comparable to the 40 Tcf ultimate potential alternative case. The major difference in trend, with respect to British Columbia production, is at the end of the outlook period where British Columbia production takes a relatively larger jump over the previous period than in either of the other two cases shown in Figure 4.6. However, in all cases British Columbia production tends to increase throughout the outlook period.

Trends in the flows of British Columbia natural gas to export markets under the 60 Tcf ultimate potential assumption are quite similar to the reference case. For instance, while flows to the Pacific Northwest market are up to 15 percent higher by the end of the outlook period, a decline in 2002 is observed similar to the reference case, associated with the introduction of northern supplies. Export flows on the links introduced from Huntingdon to California and the U.S. Rocky Mountain supply region, as in the reference case, reach the capacity constraint. However, the flow to the Rocky Mountain supply region does not decline toward the end of the outlook period as in the reference case. This is due to the relatively lower price of the British Columbia supplies corresponding to the larger resource base.

As with the 40 Tcf ultimate potential case, domestic demand responds slightly to the lower price track associated with the 60 Tcf ultimate potential case. However, a significant difference, relative to the reference case, arises in the flow of British Columbia natural gas into Alberta through the Gordondale lateral. Substantial penalties are paid by the NARG model to exceed capacity on this link. British Columbia supplies delivered into Alberta, being lower in price than the corresponding Alberta supply over the outlook period, continue to exceed capacity on the transport link. Again, this outcome is heavily dependent upon the relative costs between the two provinces as represented.

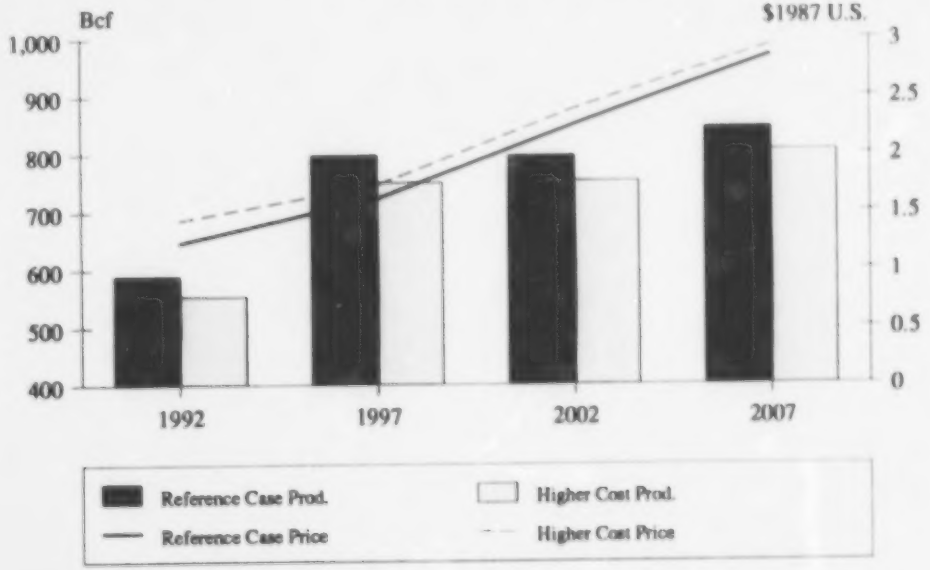
A third British Columbia alternative resource base sensitivity involved increasing the costs associated with the natural gas resource base in British Columbia and Alberta to levels corresponding to those in the NARG model as received from DFI. The resource cost curves associated with this case are provided in Appendix B.[6] The result of using these higher costs is given in Figure 4.7 in comparison to the reference case, for British Columbia production and wellhead prices. The level of resources in either province was not altered from the reference case. As with the two alternate resource scenarios previously discussed, the response in domestic demand is not significant. However, export flows are impacted to a substantial degree, mainly with respect to the Pacific Northwest market. Exports to the Pacific Northwest are reduced by over 15 percent in the near term due to the higher resource costs imposed in this case. This differential declines over the longer term to just over 5 percent below the reference case level. This outcome is due to the fact that the most significant changes to costs were made in the costs associated with existing, established reserves and thus the differences between the two cases are generally of greater magnitude in the near term.

4.2.2 Pipeline Alternative

Given the uncertainty involved with the timing of export capacity expansion associated with projects to serve California markets with Canadian supplies of natural gas, an alternative case to the reference case was run to analyse the impact of delays in the export projects. To accomplish this the PGT expansion project, the Altamont project, the Northern Border expansion and extension project and the Iroquois project were not made available to the model until 1995. The links made available to the model from Huntingdon to the California and U.S. Rocky Mountain regions were delayed until 1995 as well. As seen in Figure 4.8, British Columbia production and

Figure 4.7

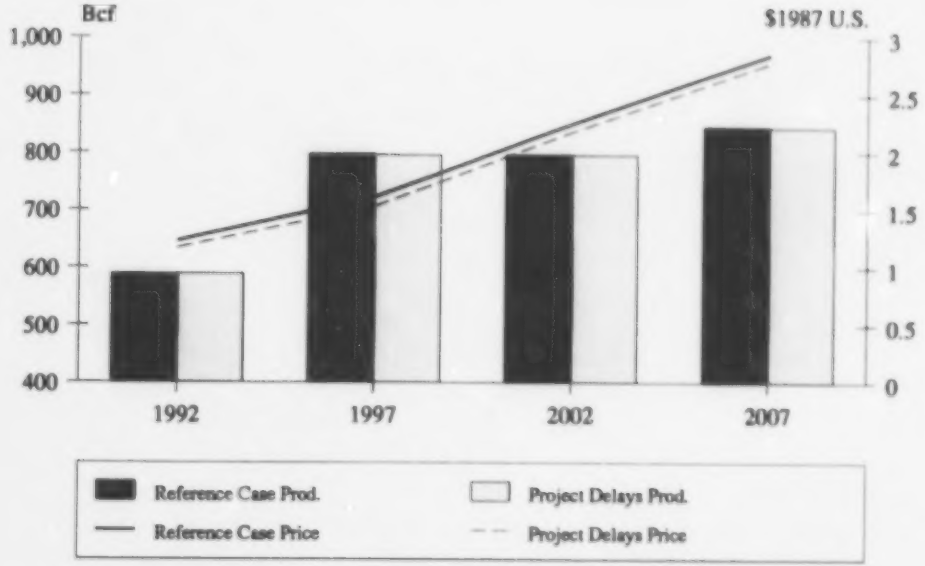
B.C. Production and Wellhead Prices
Alternative B.C. Resource Cost



SOURCE: CERI, September 1990.

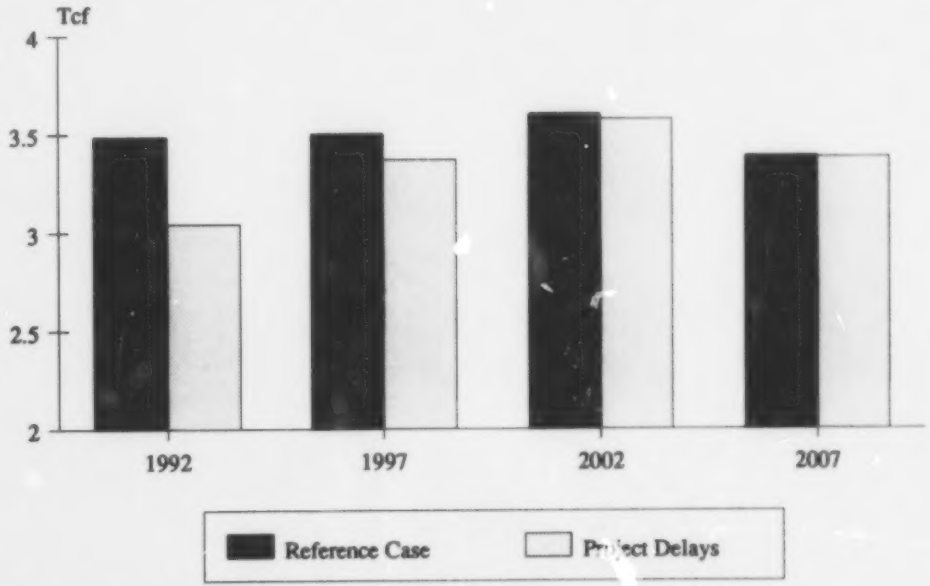
Figure 4.8

B.C. Production and Wellhead Prices
Delayed Export Capacity Expansion



SOURCE: CERI, September 1990.

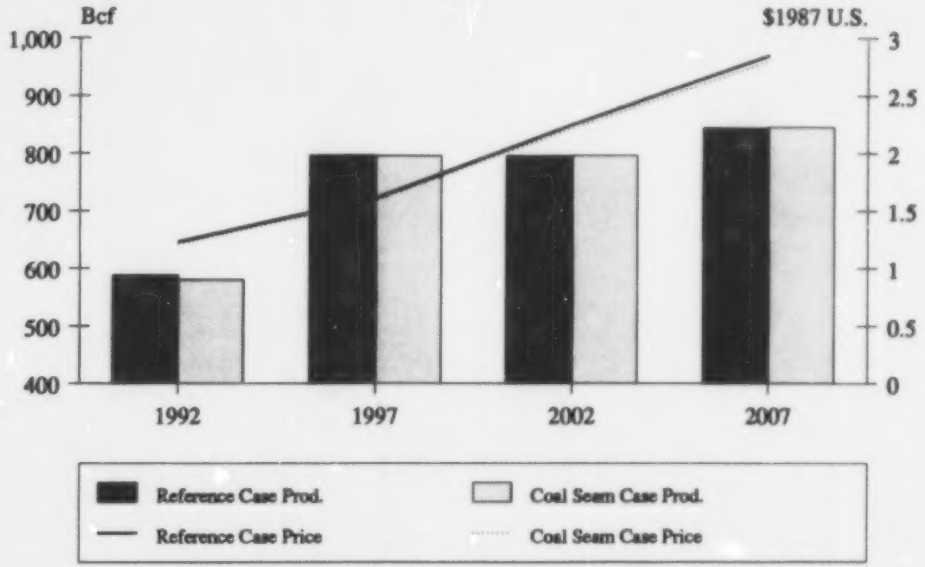
Figure 4.9
Alberta Production
Delayed Export Capacity Expansion



SOURCE: CERI, September 1990.

Figure 4.10

B.C. Production and Wellhead Prices
Alternative U.S. Resource Base Scenarios



SOURCE: CERI, September 1990.

wellhead prices are not significantly altered in this case. However, it is true that some change would likely have occurred in terms of timing of expansion between the model reporting periods 1992 and 1997 as dates of availability were changed on the links introduced from Huntingdon to California and the Rocky Mountains.

The pipeline alternative case has little impact on the flows of British Columbia natural gas, either to domestic or export markets. However, in Figure 4.9 which compares Alberta production in the reference case and the delayed expansion case, a substantial volume impact is observed. With most of the impact of delaying the proposed expansion projects being felt in the level of Alberta production, it appears as though such events may not be of too great a concern from a British Columbia perspective. Perhaps of greater concern from the point of view of the British Columbia industry would be the availability of physical capacity to move significant quantities of British Columbia natural gas supply beyond the U.S. Pacific Northwest market and on into markets such as California.

4.2.3 U.S. Resource Base Sensitivity

The impacts of a number of U.S. resource base alternatives in the NARG model are discussed in CERI Study No. 32, *Continental Natural Gas Market Canadian Export Capacity in the 90s*. The interested reader is directed to Study No. 32 for a fuller treatment of this issue. In this study, one U.S. resource base alternative was incorporated, dealing with U.S. coal seam gas production. This case involved incorporation into the NARG model of about 25 Tcf of coal seam gas in the San Juan basin supply region, at costs provided by the California Energy Commission. Production from the coal seam gas resource was constrained to just over 1.0 Bcf per day, also on the advice of the California Energy Commission.

As shown in Figure 4.10, the impact upon British Columbia production, wellhead prices and flow patterns is small. Again, detailed results are provided in Appendix A.

Footnotes

[1]National Energy Board, *Natural Gas Market Assessment, 1989-1991* (Ottawa, Ontario: Minister of Supply and Services Canada, October 1989).

[2]In 1992, the major export projects made available to the model were the Iroquois Gas Transmission System project and the Northern Border Pipeline extension and expansion. The Pacific Gas Transmission Company and the Altamont Gas Transportation Project proposals were made available to the model in 1993.

[3]Currently, pressure levels on Northwest Pipeline are lower than those on PGT such that the interconnection between the two systems at Stanfield, Oregon only permits flows off of the PGT system onto Northwest Pipeline. Therefore, at present only displacement flows of up to 300 MMcf/d may be made from Northwest Pipeline onto PGT.

[4]Canada, National Energy Board, *Reasons for Decision Westcoast Energy Inc.*, RH-1-89 (Ottawa, Ontario: Minister of Supply and Services Canada, September 1989).

[5]The 60 Tcf level of ultimate potential for northeastern British Columbia corresponds to the Geological Survey of Canada's 1982 speculative estimate of these resources. See K.E. Wallace-Dudley, et al., *Gas Resources of N. E. British Columbia*, Open File 817 (Calgary, Alberta: Geological Survey of Canada, January 1982).

[6]Recall that in the reference case, natural gas resource costs in British Columbia were reduced based upon information provided by the British Columbia MEMPR. Costs of reserves in Alberta were similarly reduced to levels comparable to those in British Columbia. Further investigation of the relative costs of reserves and future potential resources in British Columbia and Alberta will provide greater confidence in the results of this type of scenario.

Chapter 5

SUMMARY AND RECOMMENDATIONS

The results presented in Chapter 4 are optimistic with respect to British Columbia production in the 1990s and beyond. As discussed, however, areas of uncertainty do exist. For the most part, these are associated with resource levels in British Columbia, resource costs relative to those supply regions with which British Columbia gas supplies compete, and assumptions regarding access to expanded infrastructure and pipeline capacity. Therefore, as asserted previously, the results presented in this study are best viewed in light of the directional insight they provide. In so doing, it is possible to make a number of observations regarding the future development of natural gas resources in British Columbia.

5.1 Results

Directionally, the results of this study imply a significantly expanded natural gas industry in British Columbia in the 1990s and continuing over the outlook period. This result is consistent with the current level of activity in northeastern British Columbia and suggests that the trend is likely to continue for some time. This being the case, within the next few years the Westcoast system will approach full capacity utilization for the first time since the early 1970s.

High rates of utilization on the Westcoast system underscore the necessity of significant expansion if the production levels projected for the mid-1990s are to be achieved. It is currently understood that expansion on Westcoast to increase export capacity by about 200 MMcf/d could be accomplished without an increase in tolls, and that processing capacity will likely be expanded at the McMahon and Pine River processing facilities in the near future. It is also important to note that, as represented in the model, expansion of the Gordondale lateral made available to the model was fully utilized. Therefore, not all of the British Columbia gas production brought on by the model was transported via the Westcoast mainline.

By 1997, British Columbia natural gas production is projected to have increased substantially. **The implication is that by the mid-1990s, large increases in productive capacity will also be required in British Columbia.** After 1997, production in British Columbia continues to

grow and is sustained into the end of the outlook, long after production in Alberta has begun to decline. To understand why this result is obtained, consider that the level of remaining natural gas resources represented for British Columbia are roughly one third the level represented for Alberta. In 1988, production in Alberta was about nine times that in British Columbia. The analysis carried out in this study suggests that, over time and given the assumptions made, pressures will mount to increase British Columbia production levels relative to remaining potential to levels more comparable with those observed in Alberta. This result is consistent with the strong growth in natural gas exploration activity in British Columbia over recent years.

A second observation regarding development of the British Columbia natural gas resource base deals with the introduction of frontier supplies. When frontier supplies of natural gas are brought on from the Mackenzie Delta, the observation is that **British Columbia supplies at that time will be competitive and thus will not be affected to the same degree as Alberta supplies**. This result comes about since, in the near-term, Alberta supplies are being produced at a much more rapid rate, relatively speaking. The relatively greater rates of production in Alberta imply that movement up Alberta's supply curve is faster than movement up the British Columbia curve initially and, thus, Alberta production becomes more costly relative to British Columbia supplies. As a result, when the frontier supply is introduced, Alberta production bears most of the cutback, with British Columbia supplies being more competitive at that time. A second implication of the relatively more rapid production rates in Alberta is the observation discussed previously that **British Columbia production, in the outlook, remains stable even after production levels in Alberta have begun to decline**.

In the sensitivity analyses carried out, the direction of the above results did not change. In the cases employing a smaller resource base in British Columbia and/or higher resource costs, productive capacity and utilization of the transmission facilities in British Columbia are significantly taxed in the near term, with substantial growth occurring in the mid-1990s. Again, from a directional viewpoint, it is concluded that the current upstream activity within northeastern British Columbia is both justified and likely to continue for some time.

Turning to natural gas flows to British Columbia markets, the analysis suggests significant growth in exports from British Columbia over the outlook period, especially when capacity is made available to move British Columbia supplies directly into California and the Rocky Mountain

region in the U.S., as described in Chapter 3. These two transportation corridors represent over half of the increase in British Columbia production between 1992 and 1997 at about 150 Bcf per year. These flows, along with the roughly 100 Bcf per year flow via Gordondale, represent about 250 Bcf per year or about one third of the 1997 production level. **The optimism expressed in this study is thus heavily conditioned upon the availability of these three transportation options at the assumed levels of capacity.**

The fact that these incremental transmission facilities have not yet been formally applied for requires that the reader view the total production levels provided for British Columbia with this uncertainty in mind. Without the additional flows to California, the Rocky Mountain region and via Gordondale, one is left with production in British Columbia growing at a much more moderate rate. Such a moderate rate of growth would be based upon normal growth in the domestic market with an increment coming from the initiation of service to Vancouver Island, a growing market share in the Pacific Northwest, and some growth in the flows via Gordondale. **Based upon the analytical work carried out in this study, such moderate growth is quite certain. The potential for substantial growth thus lies in significantly expanded flows to extra-provincial markets beyond those currently supplied by British Columbia gas.**

As made available to the model, the transportation process to move British Columbia natural gas directly to California resulted in the delivery of supply to the California border at a competitive price in all time periods. **Thus it is suggested that the option of moving British Columbia supply to California via Northwest Pipeline and PGT warrants further analysis when better cost information becomes available.** As discussed, the flows from British Columbia to the Rocky Mountains are less certain. One must also consider the likelihood of all of these flows occurring. While one may argue that there is a significant probability that one or the other of the flows to the new markets will occur to the degree obtained here, it is less likely that they will all occur concurrently. This must be a consideration when examining the results.

5.2 Areas for Further Analysis

The uncertainty surrounding the size of the ultimate potential supply of natural gas resources in northeastern British Columbia has been mentioned. A further uncertainty lies in the costs associated with various levels of the future potential or undiscovered resources. These uncertainties apply not only to British Columbia but to the other supply regions represented in the model and, most important to this study, to the Alberta and

Rocky Mountain regions. While some work in this area has been carried by Westcoast and others, substantial additional analysis is desirable to m conclusively determine such variables as the potential for British Colum supplies to compete with Alberta supplies in markets like California, potential flows into Alberta via the Gordondale lateral.

It has also become apparent that more accurate information required regarding the cost of future expansion of such pipeline systems Northwest Pipeline, Westcoast and NOVA. This is difficult to obtain si for the most part, proposals have yet to be made for such expansions.

APPENDIX A

DETAILED RESULTS

TABLE A.1

DETAILED RESULTS - REFERENCE CASE

	1987	1992	1997	2002	2007	2012
Natural Gas Production (Tcf/yr)						
British Columbia	0.305	0.588	0.797	0.796	0.844	0.852
Alberta	2.516	3.486	3.501	3.601	3.388	2.766
Saskatchewan	0.116	0.435	0.506	0.378	0.248	0.149
Canada[a]	2.937	4.510	4.786	5.021	4.986	4.412
Average Wellhead Price ($US 1987)						
British Columbia	0.80	1.23	1.61	2.25	2.86	3.78
Alberta	1.01	1.50	2.12	2.74	3.50	4.54
Saskatchewan	1.27	1.71	2.39	3.28	4.41	5.85
Canada[a]	1.01	1.49	2.07	2.63	3.21	4.04
Corridor Flows (Tcf/yr)						
B.C. to Pacific N.W.	0.107	0.181	0.225	0.212	0.243	0.257
B.C. through Gordondale	–	0.097	0.097	0.097	0.097	0.097
B.C. to B.C. domestic	0.196	0.310	0.329	0.341	0.358	0.378
B.C. to California (Huntingdon)	–	–	0.073	0.073	0.073	0.073
B.C. to Rky. Mtn. (Huntingdon)	–	–	0.073	0.073	0.073	0.047
Net Canadian Exports (Tcf/yr)	0.951	2.004	2.068	2.019	1.654	0.940

SOURCE: Canadian Energy Research Institute.

[a]Includes northern Canadian frontier and east Canada frontier. Timing of northern Canadian supply is turn of century, eastern frontier about five years later.

TABLE A.2

DETAILED RESULTS - 40 Tcf ULTIMATE POTENTIAL FOR BRITISH COLUMBIA

	1987	1992	1997	2002	2007	2012
Natural Gas Production (Tcf/yr)						
British Columbia	0.303	0.575	0.721	0.729	0.759	0.766
Alberta	2.516	3.479	3.484	3.576	3.311	2.761
Saskatchewan	0.116	0.438	0.509	0.378	0.246	0.148
Canada[a]	2.937	4.492	4.715	4.944	4.823	4.329
Average Wellhead Price ($US 1987)						
British Columbia	0.86	1.29	1.80	2.40	3.10	4.11
Alberta	1.02	1.50	2.13	2.75	3.53	4.60
Saskatchewan	1.27	1.71	2.40	3.29	4.42	5.87
Canada[a]	1.02	1.50	2.11	2.66	3.28	4.15
Corridor Flows (Tcf/yr)						
B.C. to Pacific N.W.	0.107	0.171	0.186	0.170	0.177	0.178
B.C. through Gordondale	--	0.097	0.097	0.097	0.097	0.097
B.C. to B.C. domestic	0.196	0.307	0.320	0.331	0.346	0.361
B.C. to California (Huntingdon)	--	--	0.073	0.073	0.073	0.073
B.C. to Rky. Mtn. (Huntingdon)	--	--	0.045	0.058	0.066	0.057
Net Canadian Exports (Tcf/yr)	0.951	1.990	1.992	1.955	1.547	0.758

SOURCE: Canadian Energy Research Institute.

[a]Includes northern Canadian frontier and east Canada frontier. Timing of northern Canadian supply is turn of century, eastern frontier about five years later.

TABLE A.3

DETAILED RESULTS - 60 Tcf ULTIMATE POTENTIAL FOR BRITISH COLUMBIA

	1987	1992	1997	2002	2007	2012
Natural Gas Production (Tcf/yr)						
British Columbia	0.303	0.600	0.850	0.857	0.914	0.937
Alberta	2.516	3.505	3.514	3.661	3.338	2.737
Saskatchewan	0.116	0.433	0.503	0.375	0.248	0.152
Canada[a]	2.937	4.238	4.868	5.126	5.002	4.453
Average Wellhead Price ($US 1987)						
British Columbia	0.75	1.16	1.44	2.14	2.72	3.62
Alberta	1.01	1.49	2.11	2.72	3.46	4.47
Saskatchewan	1.26	1.70	2.38	3.26	4.39	5.85
Canada[a]	1.00	1.47	2.02	2.59	3.14	3.94
Corridor Flows (Tcf/yr)						
B.C. to Pacific N.W.	0.107	0.191	0.271	0.264	0.303	0.307
B.C. through Gordondale	–	0.097	0.097	0.097	0.097	0.097
B.C. to B.C. domestic	0.196	0.312	0.336	0.350	0.368	0.387
B.C. to California (Huntingdon)	–	–	0.073	0.073	0.073	0.073
B.C. to Rky. Mtn. (Huntingdon)	–	–	0.073	0.073	0.073	0.073
Net Canadian Exports (Tcf/yr)	0.951	2.026	2.129	2.108	1.680	0.816

SOURCE: Canadian Energy Research Institute.

[a]Includes northern Canadian frontier and east Canada frontier. Timing of northern Canadian supply is turn of century, eastern frontier about five years later.

TABLE A.4

DETAILED RESULTS - HIGHER RESOURCE COST

	1987	1992	1997	2002	2007	2012
Natural Gas Production (Tcf/yr)						
British Columbia	0.303	0.554	0.750	0.753	0.806	0.856
Alberta	2.516	3.242	3.381	3.552	3.366	2.785
Saskatchewan	0.116	0.486	0.517	0.377	0.246	0.148
Canada[a]	2.937	4.283	4.648	4.930	4.922	4.459
Average Wellhead Price ($US 1987)						
British Columbia	1.03	1.43	1.73	2.39	2.94	3.79
Alberta	1.19	1.58	2.15	2.74	3.50	4.52
Saskatchewan	1.29	1.74	2.45	3.34	4.51	5.92
Canada[a]	1.19	1.58	2.12	2.65	3.24	4.04
Corridor Flows (Tcf/yr)						
B.C. to Pacific N.W.	0.107	0.154	0.194	0.182	0.213	0.239
B.C. through Gordondale	--	0.097	0.097	0.097	0.097	0.097
B.C. to B.C. domestic	0.196	0.303	0.319	0.331	0.350	0.374
B.C. to California (Huntingdon)	--	--	0.073	0.073	0.073	0.073
B.C. to Rky. Mtn. (Huntingdon)	--	--	0.067	0.070	0.073	0.073
Net Canadian Exports (Tcf/yr)	0.951	1.802	1.944	1.951	1.640	0.834

SOURCE: Canadian Energy Research Institute.

[a]Includes northern Canadian frontier and east Canada frontier. Timing of northern Canadian supply is turn of century, eastern frontier about five years later.

TABLE A.5

DETAILED RESULTS - DELAYED PIPELINE EXPANSION

	1987	1992	1997	2002	2007	2012
Natural Gas Production (Tcf/yr)						
British Columbia	0.303	0.589	0.796	0.796	0.844	0.879
Alberta	2.516	3.043	3.370	3.577	3.382	2.776
Saskatchewan	0.116	0.387	0.494	0.379	0.254	0.154
Canada[a]	2.937	4.019	4.659	4.980	4.982	4.446
Average Wellhead Price ($US 1987)						
British Columbia	0.80	1.22	1.61	2.25	2.84	3.78
Alberta	1.00	1.46	2.11	2.73	3.49	4.53
Saskatchewan	1.25	1.69	2.36	3.23	4.36	5.82
Canada[a]	1.00	1.45	2.05	2.62	3.21	4.04
Corridor Flows (Tcf/yr)						
B.C. to Pacific N.W.	0.107	0.181	0.224	0.212	0.243	0.258
B.C. through Gordondale	--	0.097	0.097	0.097	0.097	0.097
B.C. to B.C. domestic	0.196	0.311	0.329	0.341	0.358	0.378
B.C. to California (Huntingdon)	--	--	0.073	0.073	0.073	0.073
B.C. to Rky. Mtn. (Huntingdon)	--	--	0.073	0.073	0.073	0.073
Net Canadian Exports (Tcf/yr)	0.951	1.525	1.926	1.978	1.682	0.857

SOURCE: Canadian Energy Research Institute.

[a]Includes northern Canadian frontier and east Canada frontier. Timing of northern Canadian supply is turn of century, eastern frontier about five years later.

TABLE A.6

DETAILED RESULTS - SAN JUAN COAL SEAM GAS ALTERNATIVE SCENARIO

	1987	1992	1997	2002	2007	2012
Natural Gas Production (Tcf/yr)						
British Columbia	0.303	0.580	0.796	0.797	0.846	0.890
Alberta	2.516	3.462	3.402	3.583	3.348	2.770
Saskatchewan	0.116	0.424	0.508	0.371	0.246	0.150
Canada[a]	2.937	4.467	4.706	4.929	4.940	4.433
Average Wellhead Price ($US 1987)						
British Columbia	0.79	1.21	1.59	2.22	2.80	3.69
Alberta	0.99	1.46	2.09	2.68	3.44	4.44
Saskatchewan	1.25	1.68	2.36	3.22	4.33	5.77
Canada[a]	0.99	1.46	2.03	2.59	3.16	3.96
Corridor Flows (Tcf/yr)						
B.C. to Pacific N.W.	0.107	0.182	0.223	0.211	0.242	0.265
B.C. through Gordondale	--	0.097	0.097	0.097	0.097	0.097
B.C. to B.C. domestic	0.196	0.301	0.330	0.343	0.361	0.382
B.C. to California (Huntingdon)	--	--	0.073	0.073	0.073	0.073
B.C. to Rky. Mtn. (Huntingdon)	--	--	0.073	0.073	0.073	0.073
Net Canadian Exports (Tcf/yr)	0.951	1.961	1.958	1.913	1.619	0.802

SOURCE: Canadian Energy Research Institute.

[a]Includes northern Canadian frontier and east Canada frontier. Timing of northern Canadian supply is turn of century, eastern frontier about five years later.

APPENDIX B

KEY INPUTS

TABLE B.1

EXISTING NARG MODEL TRANSPORTATION NETWORK PARAMETERS[a]

Transportation Link	Capacity (Tcf/yr)	Transport Cost (1987 $US/MMBtu)	Constituent Pipelines
1	—[b]	—[b]	—
2	—[b]	—[b]	—
3	0.50	0.00	Westcoast
4	0.73	0.16	NOVA
5	0.36	0.00	—
6	1.00	0.00	—
7	0.30	0.43	Westcoast, Northwest Pipeline
8	0.13	0.44	NOVA, Northwest Pipeline, (via PGT & PITCO)
9	0.41	0.36	NOVA, ANG, PGT
10	0.25	0.50	NOVA, Altamont
11	0.07	0.21	Northwest Pipeline
12	0.26	0.42	Kern/WYCAL
13	0.41	0.00	—
14	0.22	0.20	PGT Loop
15	0.17	0.25	Northwest Pipeline
16	0.17	0.25	Northwest Pipeline
17	0.94	0.15	PG&E
18	0.06	0.30	PG&E
19	1.00	0.00	SoCal Gas Co.
20	0.10	0.30	SoCal Gas Co.
21	1.00	0.10	San Diego Gas and Electric
22	1.00	0.50	SoCal Gas Co.
23	0.15	0.10	SoCal Gas Co.
24	0.07	0.10	PG&E
25	0.22	0.26	El Paso North, Mojave
26	0.41	0.26	El Paso - North, PG&E
27	0.26	0.26	El Paso - North
28	0.44	0.30	El Paso - South
29	0.28	0.44	Transwestern
30	1.64	0.18	NOVA
31	1.80	0.60	TransCanada

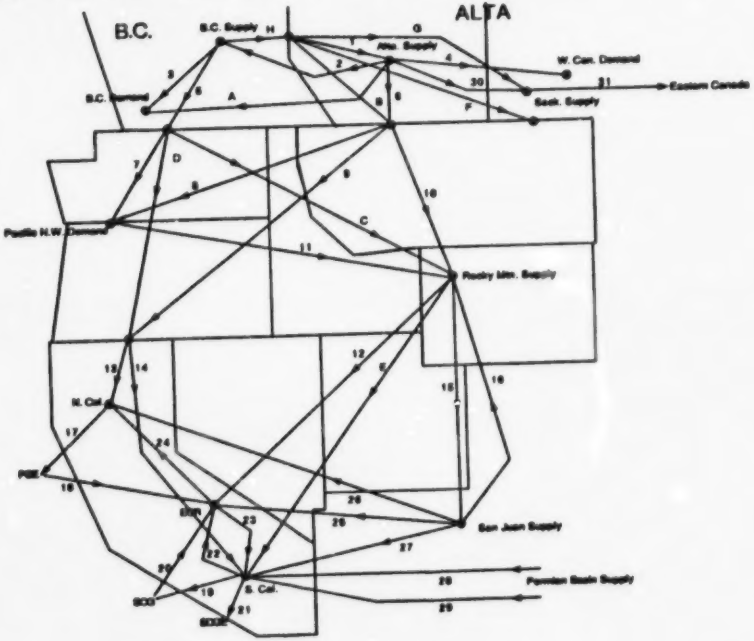
SOURCE: Canadian Energy Research Institute.

[a]The network representation corresponding to this table is provided in Figure B.1.

[b]Link turned off in current work.

Figure B.1

Transportation Options for British Columbia Natural Gas



SOURCE: CERI.

TABLE B.2

ADDITIONS TO NARG MODEL TRANSPORTATION NETWORK PARAMETERS[a]

Transportation Link	Capacity (Tcf/yr)	Transport Cost (1987 $US/MMBtu)	Constituent Pipelines
A	0.08	0.33	NOVA, Westcoast
B	—	0.00	NOVA
C	0.07	0.47	Westcoast, Northwest Pipeline
D	0.07	0.58	Westcoast, Northwest Pipeline, PGT
E	0.18	0.42	Kern/WYCAL
F	—	0.00	NOVA
G	0.05	0.20	NOVA
H	0.10	0.17	Westcoast

SOURCE: Canadian Energy Research Institute.

[a]The network representation corresponding to this table is provided in Figure B.1.

TABLE B.3

REFERENCE CASE COST INPUT - BRITISH COLUMBIA

Cumulative Additions (Tcf)	Marginal Costs ($1987 US)	Reserves Associated with R/P = 10
0.0	0.32	3.045
1.76	0.32	
3.16	0.49	
6.46	0.60	
7.96	0.61	
11.26	0.65	
16.16	1.17	
21.26	1.32	
25.76	1.48	
28.36	1.67	
30.76	1.89	
33.16	2.19	
35.66	2.66	
38.06	3.55	
40.46	6.73	

SOURCE: Canadian Energy Research Institute.

TABLE B.4

REFERENCE CASE COST INPUT - ALBERTA

Cumulative Additions (Tcf)	Marginal Costs ($1987 US)	Reserves Associated with R/P = 10
0.0	0.32	24.92
12.70	0.32	
27.70	1.04	
29.92	1.24	
35.48	1.31	
41.03	1.38	
46.54	1.44	
48.81	1.51	
54.37	1.61	
58.93	1.85	
65.48	1.98	
71.03	2.18	
76.59	2.39	
77.70	2.66	
83.26	3.03	
88.81	3.57	
94.31	4.44	
97.70	6.87	

SOURCE: Canadian Energy Research Institute.

TABLE B.5

ALTERNATIVE CASE COST INPUT - 40 Tcf
ULTIMATE POTENTIAL BRITISH COLUMBIA

Cumulative Additions (Tcf)	Marginal Costs ($1987 US)	Reserves Associated with R/P = 10
0.0	0.32	3.05
1.76	0.32	
3.16	0.50	
5.46	0.60	
6.56	0.60	
8.86	0.62	
12.36	1.12	
15.96	1.26	
18.96	1.47	
20.86	1.65	
22.66	1.87	
24.56	2.17	
26.36	2.63	
28.36	3.51	
30.06	6.83	

SOURCE: Canadian Energy Research Institute.

TABLE B.6

ALTERNATIVE CASE COST INPUT - 60 Tcf
ULTIMATE POTENTIAL BRITISH COLUMBIA

Cumulative Additions (Tcf)	Marginal Costs ($1987 US)	Reserves Associated with R/P = 10
0.0	0.32	3.05
1.76	0.32	
3.16	0.49	
8.06	0.60	
9.93	0.61	
14.04	0.62	
20.15	1.14	
26.51	1.26	
32.13	1.48	
35.37	1.63	
38.36	1.86	
41.36	2.16	
44.47	2.62	
47.47	3.52	
50.46	6.84	

SOURCE: Canadian Energy Research Institute.

TABLE B.7

ALTERNATIVE CASE COST INPUT - HIGHER RESOURCE COST CASE - BRITISH COLUMBIA

Cumulative Additions (Tcf)	Marginal Costs ($1987 US)	Reserves Associated with R/P = 10
0.0	0.60	3.05
1.76	0.60	
3.16	0.78	
6.46	0.88	
7.96	0.88	
11.26	0.90	
16.16	1.40	
21.26	1.54	
25.76	1.67	
28.36	1.83	
30.76	2.05	
33.16	2.33	
35.66	2.76	
38.06	3.59	
40.46	6.74	

SOURCE: Canadian Energy Research Institute.

TABLE B.8

ALTERNATIVE CASE COST INPUT - HIGHER RESOURCE COST CASE - ALBERTA

Cumulative Additions (Tcf)	Marginal Costs ($1987 US)	Reserves Associated with R/P = 10
0.0	0.63	24.92
12.70	0.63	
27.70	1.04	
29.92	1.24	
35.48	1.31	
41.03	1.38	
46.54	1.44	
48.81	1.51	
54.37	1.61	
58.92	1.85	
65.48	1.98	
71.03	2.18	
76.59	2.39	
77.70	2.66	
83.26	3.03	
88.81	3.57	
94.31	4.44	
97.70	6.87	

SOURCE: Canadian Energy Research Institute.

APPENDIX C

THE NORTH AMERICAN REGIONAL GAS MODEL

Appendix C

THE NORTH AMERICAN REGIONAL GAS MODEL

The North American Regional Gas (NARG) Model is an application of the Generalized Equilibrium Modelling System (GEMS), a software package developed by Decision Focus Inc. (DFI). GEMS itself consists of three principal elements:[1]

- a library of process models consisting of a set of mathematical relations that describe physical, behavioural and financial interactions of agents within an economy;
- a network describing the interaction among the different processes; and
- a solution algorithm for determining the numerical values of all variables in the model.

In the NARG model, process models are used to describe production, transmission and consumption activities within the North American natural gas market. The network which links the process models in the NARG model represents the spatial relationship between the various demand and supply regions embodied in the transportation processes which interconnect them. The algorithm used to solve the model finds a set of prices and quantities that, through time, simultaneously satisfy all physical, behavioural and financial relations embodied in the processes and linkages defined by the network. For the NARG specifically, the solution results in a number of market equilibrium prices (market clearing prices) and quantities of natural gas for a particular location at a given point in time over the time horizon of the model.

C.1 Model Structure

The following discussion has been taken largely from model documentation provided by DFI.[2] The NARG model distinguishes four major regional subdivisions including Canada, the United States, Alaska and Mexico. Alaska is represented distinctly from the Lower-48 states because of its remoteness from gas markets. Within each of the major regional divisions of North America there exists subregional detail which, while not disaggregated to the level of individual states or provinces, has been designed in consideration of where the significant demand centres are, where the various

supply regions are, and what existing and prospective future pipelines connect each.

C.1.1 Demand-Side Structure

For the United States, the degree of regional disaggregation on the demand side is governed by the census regions of the United States. These include the Pacific, Mountain, West North Central, West South Central, East North Central, East South Central, New England, Middle Atlantic and South Atlantic. There is much historical precedent to disaggregating demand regions by census region, and there is much accepted data. Furthermore, climatic distinctions among census regions are usually deemed adequate to reflect different weather and usage patterns throughout the United States.

Some of the census regions have been aggregated in the past because of commonalities amongst them. Transportation differences and climatic differences between certain of the census regions were deemed to be less important than other distinctions made within the model. The California Energy Commission (CEC) NARG model aggregated the New England region and the Mid-Atlantic region of the United States into a single aggregate region largely because the pipeline alternatives were common, there is little indigenous supply, and climatic differences are minor (relatively speaking). This aggregation has been discontinued in the version of the model used in this study to reflect the fact that, with the pipeline proposals pending at this time, the pipeline alternatives may no longer be common in these two regions. Thus, the New England and Mid-Atlantic regions are now modelled as distinct demand nodes in the model. The West North Central region and the Mountain region remain aggregated, largely because the two regions are relatively sparsely populated and little is lost by such aggregation.

The Pacific census region has been disaggregated substantially because of the particular needs of the California Energy Commission. In particular, California is represented as a separate demand region, with the rest of the Pacific region being termed the Pacific Northwest region. The California demand region is disaggregated into Northern California and Southern California. The specific gas utility service regions within Southern California--Southern California Gas, San Diego Gas and Electric, and Enhanced Oil Recovery--are further distinguished.

To summarize, the model now contains the following thirteen demand regions for the United States:

- Mid-Atlantic
- New England

- South Atlantic
- East South Central
- West South Central
- West North Central/Mountain (aggregate)
- Pacific Northwest
- Northern California (PG&E)
- Southern California Gas
- San Diego Gas and Electric
- California Enhanced Oil Recovery
- Alaska

Turning to Canada, the model aggregates the ten provinces and two territories into four aggregate demand regions. Western Canada includes all provinces west of and including Manitoba, except British Columbia. Eastern Canada includes all provinces east of the Ontario/Manitoba border and is divided into two subregions--Ontario and the rest of Eastern Canada. Ontario is distinguished because of the high concentration of population and industry in the province and because of the economic and political power Ontario wields in Canada. To summarize, Canada is subdivided into four demand regions as follows:

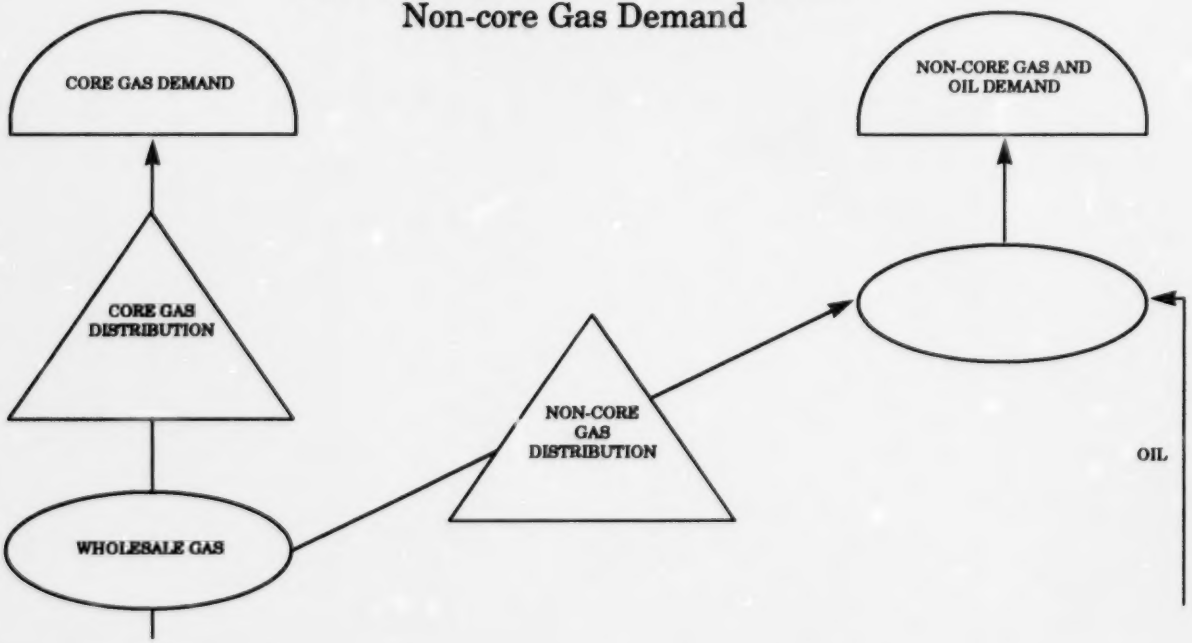
- British Columbia
- Western Canada
- Ontario
- Eastern Canada excluding Ontario

Inside each of the seventeen demand regions, the model is structured to take account of key demand-side phenomena including demand stimulation at lower prices, demand suppression at higher prices and inter-fuel substitution between oil and gas. In order to represent such phenomena, it is necessary to recognize the segmented nature of gas demand.

To properly characterize gas demand, it is important to distinguish at least two types of consumers in gas markets. The first, sometimes termed the "core market", is largely captive and exhibits relatively inelastic gas demand. The remainder, termed the "non-core market", is possessed of an immediate alternative such as fuel oil. As long as the gas price remains below that of the alternative, non-core gas demand is relatively firm. If the gas price rises to or above the price of the alternative, non-core gas demand will switch away from gas toward the alternative.

This simple characterization of gas demand can be represented in network form as shown in Figure C.1. In the figure, energy is assumed to flow along the links through the processes from bottom to top. The figure depicts two demand "tombstones", one for core demand and one for non-core demand. Each tombstone contains a demand curve, i.e., a price-quantity relationship that specifies the quantity of gas (or gas-equivalent) that will be

Figure C.1
Network Representation of Core and Non-core Gas Demand



SOURCE: Decision Focus Inc.

consumed at every possible price. Notice in the diagram that non-core demand can be satisfied either by gas or by the substitute (assumed to be oil in the diagram). Core demand can be satisfied only by gas.

Economists characterize the simple core/non-core network representation of demand using a demand curve such as that in Figure C.2. The figure delineates the size of the core and non-core markets and shows the assumed oil price. In the figure, total gas demand is shown to be equal to core demand at gas prices above the oil price and to be equal to core plus non-core demand for gas prices at or below the oil price.

In reality, core gas demand is somewhat elastic, and non-core gas demand is highly segmented, each segment facing a slightly different substitute price. Therefore, in reality, the demand graph in Figure C.2 should be "rounded off" as shown in Figure C.3. The demand curve in Figure C.3, very characteristic of gas demand, has an inelastic portion at high gas prices, a very elastic "shoulder" for gas prices in the vicinity of the oil price, and an inelastic portion at low gas prices. Results generated by the NARG model rely heavily on the distinctive pattern of gas demand in Figure C.3.

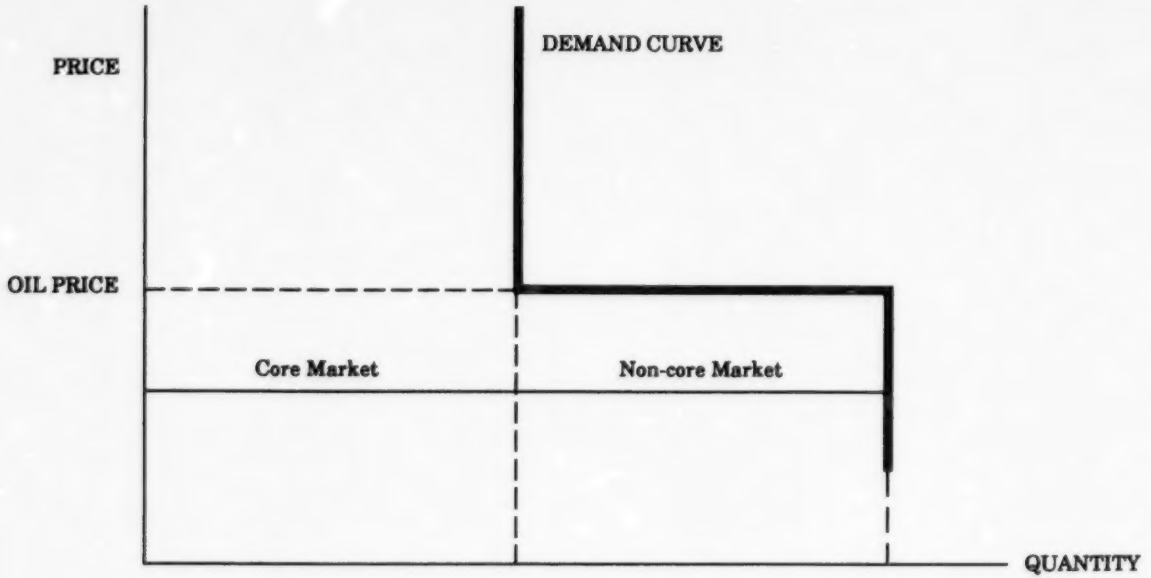
It is interesting to note that the width of the shoulder in Figure C.3 has diminished during the past two decades as the industrial sector of the United States has emigrated or shrunk. What used to be a relatively broad shoulder in a formerly industrialized economy has now become a much narrower shoulder in a service-oriented economy. Such narrowing has vital consequences for the relationship between the market-clearing price of gas relative to the price of oil, implying a much weaker degree of coupling between the two than was true historically.

Every demand region in the model contains the network structure in Figure C.1 and therefore the demand curve structure in Figure C.3. Thus, every demand region in the model represents demand stimulation/repression at different prices as well as substitution at the exogenously given price of the substitute.

The data needed for the demand side of the North American Regional Gas Supply-Demand model is the demand curve in Figure C.3 itself. In order to construct the demand curve in Figure C.3 we need its constituent elements:

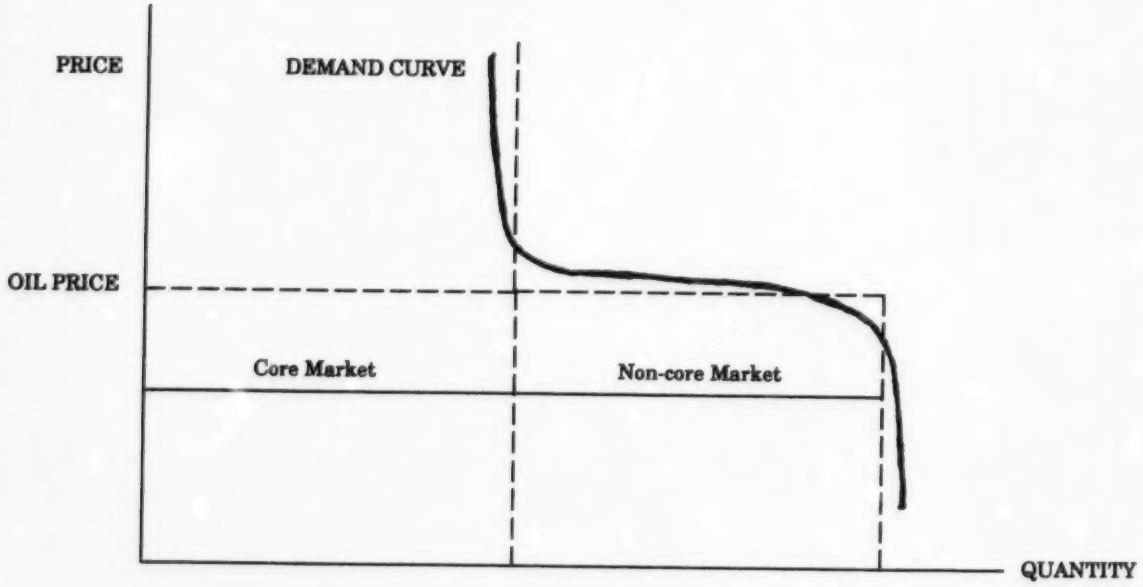
- a demand curve (price versus quantity versus time) for non-core use;
- a demand curve (price versus quantity versus time) for core use;

Figure C.2
Equivalent Representation Using Demand Curve



SOURCE: Decision Focus Inc.

Figure C.3
Gas Demand Curve



SOURCE: Decision Focus Inc.

- an estimate of non-core distribution cost, which is important in order to properly represent burner-tip gas prices relative to oil prices;
- a projected time schedule of the price of oil against which gas must compete; and
- lag parameters that simulate adjustments in capital stock necessary for gas/oil substitution.

The two demand curves within the demand tombstones for each demand region are inferred from GRI's 1989 Baseline forecast, which is revised annually. In particular, GRI's sectorial gas demand projections are divided into a core (non-substitutable) and a non-core (substitutable) component. A price is associated with each. The quantity demanded, together with the associated price, constitutes a single point on the gas demand curves. A short-run and a long-run demand elasticity are then assumed to characterize how the demand curve varies in the vicinity of the reference quantity and price.

C.1.2 Regional Structure of Supply

C.1.2.1 Regional Structure of the United States

It is not particularly useful to subdivide the supply regions in the model according to political or demographic boundaries (for example, states, provinces or census regions). Rather, it is appropriate to subdivide the supply regions according to existing and prospective natural gas producing potential, that is, to subdivide on a geological basis. In making such subdivision, consideration must be given to the structure of the existing and prospective future pipeline system. In particular, supply regions must be associated with the upstream ends of existing pipelines and with the upstream ends of anticipated new pipelines.

The supply regions in the NARG model were selected with several considerations in mind. First, when it is necessary to distinguish differences among gas producing basins in terms of transportation costs to demand regions that compete for that gas, those basins have been associated with distinct supply regions.

Second, for those sources that will require new pipeline capacity, regional supply distinctions have been made. If a particular resource producing basin relies on the addition of new pipeline capacity to become economically viable, that supply region is distinguished from other supply

regions. Indeed, in such cases, the supply region and the outward bound pipelines are inextricably linked, and must be modelled in effect as a pair.

Third, when it is necessary to distinguish resource endowment and cost differences among producing basins, those basins are distinguished by region. In general, there are substantial differences among resource producing regions with regard to extent, cost and distribution of the natural gas resource base. Some would argue that such heterogeneity of the resource base motivates an extremely detailed representation of natural gas supply. Countering such an argument is the observation that much supply-side aggregation is dictated by the specific structure of the pipeline system. Builders of the NARG Model have sought to balance the desire for more supply-side regional and technological detail with the desire to realistically represent the transportation corridors for delivering gas to market.

Fourth, many supply or pipeline projects have direct effects only in localized regions of the United States or Canada, yet the indirect effects proliferate broadly throughout all supply and demand regions of all countries represented. In effect, prices carry economic signals from the single, directly affected region to all other regions of the country along all the paths of the pipeline network. The representation of the pipeline network contains sufficient detail to represent all important existing and prospective future paths.

Fifth, government policy can be region-specific. Excessive aggregation across regions would obviate the ability of the model to properly represent government policy. For example, there are significant tax, financial, and other differences among regions necessitating regional distinctions in the model. A specific illustration is the border price regulations that were imposed by the Canadian government until recently, dictating a common border price at all United States export locations. To model such a policy, one requires substantial geographic detail. The model contains sufficient detail to represent a wide range of such phenomena.

With regard to the conventional and deep natural gas resource base, the Potential Gas Committee (PGC) regions and designations were adopted for two primary reasons. First, much thought has been given to the appropriate degree of regional disaggregation of the conventional resource base by the PGC. No reason was seen to second guess the PGC's efforts. Second, the GRI Hydrocarbon Model has a more aggregated but quite similar regional structure to the PGC regions. Indeed, aggregates of the PGC regions correspond rather closely to the GRI Hydrocarbon Model supply regions. By selecting the PGC regions for the conventional gas resource base, it is possible to access not only the PGC resource base estimates but also the GRI Hydrocarbon Model estimates.

The focus of the Potential Gas Committee (PGC), GRI Hydrocarbon, United States Geological Survey (USGS), Department of Energy (DOE), and other resource base efforts is only upon conventional natural gas. Unconventional gas (tight sands, methane from coal deposits and devonian shale) is associated in the model with conventional gas supply regions and is distributed among the conventional gas supply regions as dictated by their actual physical location. In short, the unconventional gas resource base is distinguished in the same degree of regional detail as the conventional gas resource base and the realities of where it occurs are properly represented. Using the same regional distinctions for unconventional as well as conventional gas is particularly convenient and thought to be proper because the unconventional gas resource must enjoy the same access to the transportation system as conventional. Coal gasification is regionalized according to coal producing regions of the United States. The major coal producing regions of the United States have been associated with various PGC supply regions and have been placed into the corresponding aggregate NARG model gas supply regions. For example, the North Dakota coal region (where mine-mouth coal gasification might occur) is considered to lie within the Northern Great Plains supply region. Small, exotic sources such as methane from waste or biogas are positioned within the various demand regions, representing the fact that they use only the distribution system, not the transportation system.

The North American Regional Gas model contains a detailed representation of the existing and potential future supply options within each of these regions.

C.1.2.2 Regional Structure of Canada

The regional structure of the Canadian gas system in the NARG and the supporting resource data are taken directly from the structure developed by the University of Saskatchewan and the Canadian Energy Research Institute (CERI) as characterized in CERI Study No. 26,[3] and Rinholm (1987).[4] The Canadian natural gas resource base is distinguished as follows:

- British Columbia
- Alberta
- Saskatchewan
- Eastern Canada
- Mackenzie Delta
- Canadian Arctic (Beaufort Sea, Arctic Islands)

As with the United States, the particular regional disaggregation for Canada was chosen with several purposes in mind. First, it was necessary to survey and represent the location of the primary gas deposits in

Canada. It is known that the vast majority of economic Canadian gas occurs within Alberta. Yet, it is also known that there are significant deposits in British Columbia and Saskatchewan and that the latter deposits are positioned differently with regard to the Canadian transportation system.

Second, the Canadian resource base must be distinguished at a level of geographic detail necessary to support analysis of six prospective Canadian border export locations to the United States. This includes the new link into New England. That is, the level of border import and demand detail within the United States dictates the level of resource base disaggregation needed for Canada.

Third, it was necessary to distinguish key demand patterns in Canada, which in the past have influenced not only delivered gas prices in Canada but also export pricing policy. In particular, much of Canadian gas demand occurs within Ontario, which is Canada's most populous and most politically influential province. However, Ontario demand must be served through long distance pipeline from Alberta either indirectly through the Great Lakes system or directly through the TransCanada pipeline. Alberta and points intermediate (i.e., Saskatchewan) must therefore be distinguished.

Fourth, it is necessary to distinguish the Northern Arctic gas resource base in sufficient detail; otherwise, one cannot predict what is the most economical resource base exploitation pattern and what will be its impact on gas prices throughout North America. In particular, the supply structure representing Canada must be sufficiently detailed to analyse whether the "explore successively up the Mackenzie" strategy is more economical than the "build a pipeline from the North Slope" strategy. The geographic structure contains sufficient level of detail to answer such questions.

Within each of the six Canadian supply regions, the economics of conventional and unconventional gas production at various depth intervals have been represented. Canadian resource cost and geological data were provided to DFI by the National Energy Board of Canada. As noted in the text, CERI has adjusted the geological data somewhat.

C.1.2.3 Nature of the Supply Data

The most elemental economic measure of the cost and extent of the gas resource base is the so-called "resource marginal cost curve" or "resource supply curve", which plots marginal cost against cumulative future additions to proved reserves. The concept and use of a resource marginal cost is discussed in detail in Haas, Nesbitt, and Singh (1987),[5] and rather extensive

references to the economics literature are given. Rather than repeating that discussion, a simple static supply curve or static marginal cost curve can be used to illustrate. No generality will be lost by this simplification; however, it is emphasized that the NARG model employs a very general inter-temporal model of depletable resource production based on a general resource marginal cost curve.

The resource supply curve represents how much gas can be produced by producers at every possible price level. It is not a one-dimensional characterization of the resource base, one that merely "adds up" Btus in the ground. Rather, it is a two-dimensional characterization, specifying precisely how much gas could and would be produced at each given wellhead price level.

It is imperative to consider both cost and quantity and to neglect neither. Only by considering both can we quantify such lay notions as "abundance" or "scarcity" of gas supply. An abundant resource case is one in which the cost of producing each given quantity of resource is low, or alternatively that the quantity of resource available at each given price level is high. Conversely, a scarce resource case is one in which the cost of producing each given quantity of resource is high, or alternatively that the quantity of resource available at each given price level is low. Scarcity and abundance are represented using resource supply curves. How could such concepts be represented without appealing simultaneously to both the cost and Btu dimensions? Clearly they cannot.

C.1.3 Geographic Representation of Gas Import Alternatives

Border import locations are positioned at various points along the United States-Canadian border and the United States-Mexican border. There are six border import locations from Canada. There are two prospective border import locations from Mexico represented in the model. LNG import locations are positioned along the East, Gulf, and West coasts at various existing and prospective future locations. The geographic structure of the LNG import locations was discussed previously in conjunction with the demand regions.

Footnotes

[1]A technical description of these three elements can be found in R.L. Phillips, "A Methodology and Software System for Linking Economic Models" *Large Scale Systems 4* (Holland: North Holland Publishing Company, 1983).

[2]See *An Overview of the Generalized Equilibrium Modeling System (GEMS)* (Palo Alta, California: Decision Focus Inc., 1983); and *The California Energy Commission North American Regional Gas Supply-Demand Model* (Palo Alto, California: Decision Focus Inc., 1989).

[3]Kevin J. Brown, *Towards a Continental Natural Gas Market: Historical Perspective and Long-Term Outlook*, CERI Study No. 26 (Calgary, Alberta: Canadian Energy Research Institute, August 1989).

[4]R. Rinholm, "The Canadian Natural Gas Industry: Options and Opportunities," Master of Science dissertation (Saskatoon, Saskatchewan: University of Saskatchewan, 1987).

[5]S. Haas, D. Nesbitt, and J. Singh, *The GRI North American Regional Gas Supply-Demand Model*, GRI Report Number 87-0122 (Palo Alto, California: Gas Research Institute, 1987).

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90-10 The Outlook for the Natural Gas Industry in British Columbia. David H. Maerz. Published in the proceedings of the Twelfth North American Conference of the International Association for Energy Economists, Ottawa, Ontario, October 1-3, 1990.

90-9 World Oil Demand in the Mid-90s. Anthony E. Reinsch. Presented at the Ninth CERI International Oil and Gas Markets Conference, Calgary, Alberta, September 23-25, 1990.

90-8 World Oil Market Projections: Gauging the Uncertainties. Anthony E. Reinsch. Published in the proceedings of the Newfoundland Offshore Industries' Association Conference, "Offshore Newfoundland in the 1990s: An Assessment of the Economic Environment", St. John's, Nfld., June 4-6, 1990.

90-7 Canadian Capacity Requirements in Context. Morgan MacRae. Presented at Energy and Electricity: A Conference on Electric Power Planning in the 1990s, Montreal, Quebec, June 3-5, 1990.

90-6 Canada's Leading Alternative Fuels. Michelle Heath. Presented to the Conference on Oxygenated Fuels in Europe, London, England, May 22-23, 1990.

90-5 Planning Uncertainties for the 1990s: World Oil Prices. Anthony E. Reinsch. Seminar presentation, Calgary, Alberta, May 17, 1990.

90-4 Finding and Development Costs: Merits and Pitfalls. Michele McLachlan. Presented to the Economic Society of Calgary, Calgary, Alberta, April 25, 1990.

90-3 World Oil Market Projections: 1990-2005. Anthony E. Reinsch. Seminar for CERI Study No. 34, Calgary, Alberta, April 19, 1990.

90-2 Natural Gas: Fuel of the 1990s. Leonard Coad. Presented at the conference "Gas Marketing: Current Issues for Producers," Calgary, Alberta, April 9, 1990.

90-1 Electric Power in the 1990s: Critical Issues, Critical Choices. Anthony E. Reinsch. Presented to the Political Economy of Electric Power in Canada Conference, London, Ontario, March 23-25, 1990.

89-10 Outlook for the Canadian Crude Oil Market. Anthony E. Reinsch. Presentation to the Petroleum Joint Ventures Association, Calgary, Alberta, November 1, 1989.

89-9 World Energy Conference Technical Section 3.3: A Review of Papers. Anthony E. Reinsch. Presentation to the World Energy Conference, Montreal, Quebec, September 19, 1989.

89-8 Canada's Experience with Oil Megaprojects. G. E. Angevine. Presentation at the 8th International Symposium on Petroleum Economics, Quebec City, Quebec, September 14, 1989.

89-7 Interpreting the World Oil Market: Fundamentals and Forecasting. Anthony E. Reinsch. Presentation to the Alberta Summer Institute for Petroleum Industry Development, Calgary, Alberta, July 4, 1989.

89-6 Evolution of World Oil Prices. Anthony E. Reinsch. Presentation to the Exploration Update '89 Conference, Calgary, Alberta, June 14, 1989.

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89-4 Oil and Gas Finding Costs in Alberta: Survival in an Uncertain Environment. Anthony E. Reinsch. Presentation to Petroleum Society of CIM, Calgary, Alberta, May 17, 1989.

89-3 Industrial Natural Gas Demand. Merete Heggelund. Presentation to the Canadian Gas Association, Economics/Statistics Committee, Edmonton, Alberta, May 8, 1989.

89-2 Critical Issues in Bioenergy Development: Prices and Prospects Through 2010. Anthony E. Reinsch. Presentation to The Seventh Canadian Bio-energy Research and Development Seminar, Ottawa, Ontario, March 24-26, 1989.

89-1 Towards a Commercial Future: Ethanol and Methanol as Alternative Transportation Fuels. Michelle Heath. Presentation to Alternative Fuels Forum Participants, Regina, Saskatchewan, March 22, 1989.

88-9 Stability Within Uncertainty: Evolution of the World Oil Market. A. E. Reinsch. Presentation to the Canadian Society of Petroleum Geologists, Calgary, Alberta, December 1988.

88-8 Stability Within Uncertainty: Evolution of the World Oil Market. A. E. Reinsch. Presentation to the 10th Annual Meeting, International Association for Energy Economics, Houston, Texas, November 1988.

88-7 The Canadian Natural Gas Resource Base: Reserves, Deliverability and Potential. Kevin J. Brown. Presentation to the CERI/Institute of Gas Technology Canada/U.S. Gas Trade Conference, Chicago, Illinois, November 14-16, 1988.

88-6 Perspectives on Canadian/American Trade in Energy. Dr. G. E. Angevine. Presentation to the Canadian Association of Petroleum Production Accounting Conference, Calgary, Alberta, October 1988.

88-5 Renewable Energy: Offspring of OPEC? A. E. Reinsch. Presentation to the Wood Energy Symposium, Fredericton, New Brunswick, October 1988.

88-4 Energy Options: A Critical Review. A. E. Reinsch. Presentation to the Seventh CERI International Oil and Gas Markets Conference, Calgary, Alberta, September 1988.

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88-2 Towards a Continental Natural Gas Market: Some Strategic Implications. Kevin J. Brown. Presentation to the U.S. Gas Market in Transition Conference, Calgary, Alberta, June 22-23, 1988.

88-1 Issues in Canada-U.S. Hydrocarbon Trade. Anthony E. Reinsch. Presentation to the Trinational Energy Policy Workshop, Stanford University, Stanford, California, March 21-22, 1988.

87-6 Canadian Natural Gas Supply and its Inter-Relationship with the North American Natural Gas Market. Kevin Brown. Presentation to the Ninth Annual North American Meeting International Association of Energy Economists, Washington D.C., November 1987. Published in the Proceedings, November 1987.

87-5 Notes for Discussion of Aspects of Energy Security in Canada. Morgan MacRae and Merete Heggelund. Presented to Energy Options Seminar, "Energy: The International Perspective," Halifax, Nova Scotia, November 3, 1987.

87-4 A Survey of Energy in Canada. Anthony E. Reinsch. Presentation to the World Energy Congress, Institute for Electrical and Electronic Engineering, Sao Paulo, Brazil, August 19-20, 1987.

87-3 The Economics of Conventional Oil Supply in Saskatchewan. James N. Tanner. Paper presented to the Annual Meeting of the International Association of the Energy Economists, Calgary, Alberta, July 1987. Published in the Proceedings.

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87-1 Industrial Cogeneration in Canada: Prospects and Perspectives. Anthony E. Reinsch. Presentation to the conference on Cogeneration and Parallel Electric Power Generation: The Opportunities, co-sponsored by the Canadian Energy Research Institute and the Ontario Ministry of Energy, Toronto, Ontario, March 30-31, 1987. Published in the Conference Proceedings, September, 1987. ISBN 0-920522-43-2.

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Annual Reports

Board of Directors' Report for the Year Ended March 31, 1990.

Board of Directors' Report for the Year Ended March 31, 1989.

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